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Equipment Leaks of VOC (Volatile Organic Compounds) in Natural Gas Production Industry Background Information for Proposed Standards

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Research Triangle Park, NC

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This report discusses the regulatory alternatives considered during development of the proposed new source performance standards and the environmental and economic impacts associated with each regulatory alternative.

16. ABSTRACT

Standards of performance for the control of VOC emissions from equipment leaks at natural gas processing plants are being proposed under Section 111 of the Clean Air Act. This document contains background information and environmental and economic impact assessments of the regulatory alternatives considered in developing the proposed standards.

17. KEY WORDS AND DOCUMENT ANALYSIS

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Equipment Leaks of VOC in Natural Gas Production Industry -

Background Information for Proposed Standards

Emission Standards and Engineering Division

U.S ENVIRONMENTAL PROTECTION AGENCY
Office of Air, Noise, and Radiation
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

December 1983

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ENVIRONMENTAL PROTECTION AGENCY

Background Information
and Draft
Environmental Impact Statement
for Equipment Leaks of VOC in Natural
Gas Production Industry
Prepared by:

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1. The proposed standards of performance would limit emissions of VOC from equipment leaks at new, modified, and reconstructed affected facilities at natural gas plants. Section 111 of the Clean Air Act (42 U.S.C. 7411), as amended, directs the Administrator to establish standards of performance for any category of new stationary source of air pollution that "... causes or contributes significantly to air pollution which may reasonably be anticipated to endanger public health or welfare."

2. Copies of this doucment have been sent to the following Federal Departments: Labor, Health and Human Services, Defense, Transportation, Agriculture, Commerce, Interior, and Energy; the National Science Foundation; the Council on Environmental Qualtiy; members of the State and Territorial Air Pollution Program Administrators; the Association of Local Air Pollution Control Officials; EPA Regional Administrators; and other interested parties.

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To Convert Metric Unit	Multiply By Conversion Factor	To Obtain English Unit
centimeter (cm)	0.39	inch (in.)
meter (m)	3.28	feet (ft.)
liter (l)	0.26	U.S. gallon (gal)
cubic meter (m^3)	264.2	U.S. gallon (gal)
cubic meter (m^3)	6.29	barrel (oil) (bbl)
cubic meter (m^3)	35	cubic feet (ft^3)
kilogram (kg)	2.2	pound (lb)
megagram (Mg)	1.1	ton
gigagram (Gg)	2.2	million pounds (10^6 lbs)
gigagram (Gg)	1102	ton
joule (J)	9.48×10^{-4}	British thermal unit (Btu)

PREFIXES

Prefix	Symbol	Multiplication Factor
tera	T	10^{12}
giga	G	10^9
mega	M	10^6
kilo	k	10^3
centi	c	10^{-2}
milli	m	10^{-3}
micro	μ	10^{-6}

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1.0 SUMMARY

1.1 REGULATORY ALTERNATIVES

Standards of performance for new stationary sources of volatile organic compounds (VOC) from fugitive emission sources in the onshore natural gas production industry are being developed under the authority of Section 111 of the Clean Air Act. These standards would reduce emissions caused by leaks from valves, relief valves, open-ended lines, compressor seals, pump seals, and sampling connections. Because VOC is emitted as a result of equipment leaks, the emissions are referred to as fugitive emissions, and the process equipment are referred to as fugitive emission sources in this document. However, the title of this document has been changed from the title used for previous drafts (VOC Fugitive Emissions in On-Shore Natural Gas Production Industry - Background Information for Proposed Standards) to "Equipment Leaks of VOC in Natural Gas Production Industry - Background Information for Proposed Standards" to clarify that the fugitive emissions are the result of equipment leaks.

Four regulatory alternatives were considered. Regulatory Alternative I is the baseline alternative and represents the level of control that would exist in the absence of any standards of performance. Requirements of Alternative II are:

- o Quarterly instrument monitoring for leaks from valves, relief valves, and compressor seals;
- o Quarterly instrument and weekly visual monitoring for leaks from pump seals; and
- o Installation of caps (including plugs, flanges, or second valves) on open-ended lines.

Regulatory Alternative III is more restrictive than Alternative II.

The requirements are as follows:

- Monthly monitoring of valves (if a particular valve is found not to be leaking for 3 successive months, then 2 months may be skipped before the next time it is monitored with an instrument);
- Monthly monitoring of relief valves and pump seals, and weekly visual inspection of pump seals;
- Installation of a vent control system to control compressor seal emissions;
- Installation of closed purge sampling systems on sampling connections; and
- Installation of caps (including plugs, flanges, or second valves) on open-ended lines.

Regulatory Alternative IV is the most stringent of the alternatives. Monthly instrument monitoring would be required for valves, relief valves would be equipped with a rupture disc, and pumps would be required to have dual mechanical seals. Other requirements would be the same as Alternative III.

1.2 ENVIRONMENTAL IMPACT

Fugitive emissions of VOC from affected gas production facilities under Regulatory Alternative I would be approximately 22,000 Mg/yr in 1987, the fifth year of implementation. This is compared to 6,900, 6,200, and 5,000 Mg/yr under Alternatives II, III, and IV, respectively.

In addition to reducing emissions to the atmosphere, Alternatives II, III, and IV would reduce liquid leaks, thereby reducing wastewater treatment needs. Some solid waste would be generated by the replacement of existing equipment (e.g., replaced seal packing, rupture discs). However, this amount of solid waste would be very small in comparison to existing levels of solid waste generated by gas plants.

Energy savings from VOC and non-VOC hydrocarbons would result under Regulatory Alternatives II-IV. Under Alternative II, hydrocarbons recovered during the fifth year of implementation would have an energy content of approximately 6,400 terajoules. This is equivalent to the heating valve of approximately 1,050 barrels of crude oil. Hydrocarbons recovered under Alternative III would result in slightly less energy savings than Alternative II, because emissions are not recovered from compressor seal leaks. Alternative IV would result in energy savings of approximately 6,900 terajoules, which is approximately equivalent to the heating value of 1,120 barrels of crude oil.

A more detailed analysis of environmental and energy impacts is presented in Chapter 7. A summary of the environmental impacts associated with the four regulatory alternatives is shown in Table 1-1.

1.3 ECONOMIC IMPACT

Costs incurred by the onshore natural gas production industry under Regulatory Alternative II would actually be a credit due to the value of the recovered hydrocarbons. In the fifth year of implementation of Alternative II, a net annual credit of $160,000 would result. Net annual costs incurred during the fifth year under Alternative III would be approximately $510,000; under Regulatory Alternative IV net annual costs of over $7 million are incurred. A more detailed analysis of costs is included in Chapter 8. Price impacts of the regulatory alternatives are expected to be slight regardless of the regulatory alternative. No plant closures or curtailments are expected, and effects on industry profitability, output, growth, and other factors would be negligible or zero. A more detailed economic analysis is presented in Chapter 9. A summary of environmental, energy, and economic impacts associated with the alternatives is shown in Table 1-1.

Table 1-1. ENVIRONMENTAL, ENERGY, AND ECONOMIC IMPACTS OF REGULATORY ALTERNATIVES

Administrative Action	Air Impact	Water Impact	Solid Waste Impact	Energy Impact	Noise Impact	Economic Impact
Regulatory Alternative I (No action)	0	0	0	0	0	0
Regulatory Alternative II	+2**	+1**	0	+1*	0	+1*
Regulatory Alternative III	+2**	+1**	0	+1*	0	-1*
Regulatory Alternative IV	+2**	+1**	0	+1*	0	-1*

KEY: + Beneficial impact
- Adverse impact

0 No impact
1 Negligible impact
2 Small impact
3 Moderate impact
4 Large impact

* Short-term impact
** Long-term impact
*** Irreversible impact

2.0 INTRODUCTION

2.1 BACKGROUND AND AUTHORITY FOR STANDARDS

Before standards of performance are proposed as a Federal regulation, air pollution control methods available to the affected industry and the associated costs of installing and maintaining the control equipment are examined in detail. Various levels of control based on different technologies and degrees of efficiency are expressed as regulatory alternatives. Each of these alternatives is studied by EPA as a prospective basis for a standard. The alternatives are investigated in terms of their impacts on the economics and well-being of the industry, the impacts on the national economy, and the impacts on the environment. This document summarizes the information obtained through these studies so that interested persons will be privy to the information considered by EPA in the development of the proposed standard.

Standards of performance for new stationary sources are established under Section 111 of the Clean Air Act (42 U.S.C. 7411) as amended, hereinafter referred to as the Act. Section 111 directs the Administrator to establish standards of performance for any category of new stationary source of air pollution which ". . . causes, or contributes significantly to air pollution which may reasonably be anticipated to endanger public health or welfare."

The Act requires that standards of performance for stationary sources reflect, ". . . the degree of emission reduction achievable which (taking into consideration the cost of achieving such emission reduction, and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated for that category of sources." The standards apply only to stationary sources, the construction or modification of which commences after regulations are proposed by publication in the Federal Register.

The 1977 amendments to the Act altered or added numerous provisions that apply to the process of establishing standards of performance.

1. EPA is required to review the standards of performance every 4 years and, if appropriate, revise them.

2. EPA is authorized to promulgate a standard based on design, equipment, work practice, or operational procedures when a standard based on emission levels is not feasible.

3. The term "standards of performance" is redefined, and a new term "technological system of continuous emission reduction" is defined. The new definitions clarify that the control system must be continuous and may include a low- or non-polluting process or operation.

4. The time between the proposal and promulgation of a standard under section 111 of the Act may be extended to 6 months.

Standards of performance, by themselves, do not guarantee protection of health or welfare because they are not designed to achieve any specific air quality levels. Rather, they are designed to reflect the degree of emission limitation achievable through application of the best adequately demonstrated technological system of continuous emission reduction, taking into consideration the cost of achieving such emission reduction, any nonair-quality health and environmental impacts, and energy requirements.

Congress had several reasons for including these requirements. First, standards with a degree of uniformity are needed to avoid situations where some States may attract industries by relaxing standards relative to other States. Second, stringent standards enhance the potential for long-term growth. Third, stringent standards may help achieve long-term cost savings by avoiding the need for more expensive retrofitting when pollution ceilings may be reduced in the future. Fourth, certain types of standards for coal-burning sources can adversely affect the coal market by driving up the price of low-sulfur coal or effectively excluding certain coals from the reserve base because their untreated pollution potentials are high. Congress does not intend that new source performance standards contribute to these problems. Fifth, the standard-setting process should create incentives for improved technology.

Promulgation of standards of performance does not prevent State or local agencies from adopting more stringent emission limitations for the same sources. States are free under Section 116 of the Act to establish even more stringent emission limits than those established under Section 111 or those necessary to attain or maintain the National Ambient Air Quality Standards (NAAQS) under Section 110. Thus, new sources may in some cases be subject to limitations more stringent than standards of performance under Section 111, and prospective owners and operators of new sources should be aware of this possibility in planning for such facilities.

A similar situation may arise when a major emitting facility is to be constructed in a geographic area that falls under the prevention of significant deterioration of air quality provisions of Part C of the Act. These provisions require, among other things, that major emitting facilities to be constructed in such areas are to be subject to best available control technology. The term Best Available Control Technology (BACT), as defined in the Act, means

> . . . an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this Act emitted from, or which results from, any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of each such pollutant. In no event shall application of 'best available control technology' result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to Sections 111 or 112 of this Act. (Section 169(3))

Although standards of performance are normally structured in terms of numerical emission limits where feasible, alternative approaches are sometimes necessary. In some cases physical measurement of emissions from a new source may be impractical or exorbitantly expensive. Section 111(h) provides that the Administrator may promulgate a design or equipment standard in those cases where it is not feasible to prescribe or enforce a standard of performance. For example, emissions of hydrocarbons from storage vessels for petroleum liquids are greatest during tank filling. The nature of the emissions, high concentrations for short periods during filling and low concentrations for longer periods during storage, and the configuration of storage tanks make direct emission measurement impractical. Therefore, a more practical approach to standards of performance for storage vessels has been equipment specification.

In addition, Section 111(j) authorizes the Administrator to grant waivers of compliance to permit a source to use innovative continuous emission control technology. In order to grant the waiver, the Administrator must find: (1) a substantial likelihood that the technology will produce greater emission reductions than the standards require or an equivalent reduction at lower economic energy or environmental cost; (2) the proposed system has not been adequately demonstrated; (3) the technology will not cause or contribute to an unreasonable risk to the public health, welfare, or safety; (4) the governor of the State where the source is located consents; and (5) the waiver will not prevent the attainment or maintenance of any ambient standard. A waiver may have conditions attached to assure the source will not prevent attainment of any NAAQS. Any such condition will have the force of a performance standard. Finally, waivers have definite end dates and may be terminated earlier if the conditions are not met or if the system fails to perform as expected. In such a case, the source may be given up to 3 years to meet the standards with a mandatory progress schedule.

2.2 SELECTION OF CATEGORIES OF STATIONARY SOURCES

Section 111 of the Act directs the Adminstrator to list categories of stationary sources. The Administrator ". . . shall include a category of sources in such list if in his judgement it causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare." Proposal and promulgation of standards of performance are to follow.

Since passage of the Clean Air Amendments of 1970, considerable attention has been given to the development of a system for assigning priorities to various source categories. The approach specifies areas of interest by considering the broad strategy of the Agency for implementing the Clean Air Act. Often, these "areas" are actually pollutants emitted by stationary sources. Source categories that emit these pollutants are evaluated and ranked by a process involving such factors as: (1) the level of emission control (if any) already required by State regulations, (2) estimated levels of control that might be required from standards of performance for the source category, (3) projections of growth and replacement of existing facilities for the source category, and (4) the estimated incremental amount of air pollution that could be prevented in a preselected future year by standards of performance for the source category. Sources for which new source performance standards were promulgated or under development during 1977, or earlier, were selected on these criteria.

The Act amendments of August 1977 establish specific criteria to be used in determining priorities for all major source categories not yet listed by EPA. These are: (1) the quantity of air pollutant emissions that each such category will emit, or will be designed to emit; (2) the extent to which each such pollutant may reasonably be anticipated to endanger public health or welfare; and (3) the mobility and competitive nature of each such category of sources and the consequent need for nationally applicable new source standards of performance.

The Administrator is to promulgate standards for these categories according to the schedule referred to earlier.

In some cases it may not be feasible immediately to develop a standard for a source category with a high priority. This might happen when a program of research is needed to develop control techniques or because techniques for sampling and measuring emissions may require refinement. In the developing of standards, differences in the time required to complete the necessary investigation for different source categories must also be considered. For example, substantially more time may be necessary if numerous pollutants must be investigated from a single source category. Further, even late in the development process the schedule for completion of a standard may change. For example, inablility to obtain emission data from well-controlled sources in time to pursue the development process in a systematic fashion may force a change in scheduling. Nevertheless, priority ranking is, and will continue to be, used to establish the order in which projects are initiated and resources assigned.

After the source category has been chosen, the types of facilities within the source category to which the standard will apply must be determined. A source category may have several facilities that cause air pollution, and emissions from some of these facilities may vary from insignificant to very expensive to control. Economic studies of the source category and of applicable control technology may show that air pollution control is better served by applying standards to the more severe pollution sources. For this reason, and because there is no adequately demonstrated system for controlling emissions from certain facilities, standards often do not apply to all facilities at a source. For the same reasons, the standards may not apply to all air pollutants emitted. Thus, although a source category may be selected to be covered by a standard of performance, not all pollutants or facilities within that source category may be covered by the standards.

2.3 PROCEDURE FOR DEVELOPMENT OF STANDARDS OF PERFORMANCE

Standards of performance must (1) realistically reflect best demonstrated control practice; (2) adequately consider the cost, the nonairquality health and environmental impacts, and the energy requirements of such control; (3) be applicable to existing sources that are modified or reconstructed as well as new installations; and (4) meet these conditions for all variations of operating conditions being considered anywhere in the country.

The objective of a program for developing standards is to identify the best technological system of continuous emission reduction that has been adequately demonstrated. The standard-setting process involves three principal phases of activity: (1) information gathering, (2) analysis of the information, and (3) development of the standard of performance.

During the information-gathering phase, industries are queried through a telephone survey, letters of inquiry, and plant visits by EPA representatives. Information is also gathered from many other sources to provide reliable data that characterize the pollutant emissions from well-controlled existing facilities.

In the second phase of a project, the information about the industry and the pollutants emitted is used in analytical studies. Hypothetical "model plants" are defined to provide a common basis for analysis. The model plant definitions, national pollutant emission data, and existing State regulations governing emissions from the source category are then used in establishing "regulatory alternatives." These regulatory alternatives are essentially different levels of emission control.

EPA conducts studies to determine the impact of each regulatory alternative on the economics of the industry and on the national economy, on the environment, and on energy consumption. From several possibly applicable alternatives, EPA selects the single most plausible regulatory alternative as the basis for a standard of performance for the source category under study.

In the third phase of a project, the selected regulatory alternative is translated into a standard of performance, which, in turn, is written in the form of a Federal regulation. The Federal regulation, when applied to newly constructed plants, will limit emissions to the levels indicated in the selected regulatory alternative.

As early as is practical in each standard-setting project, EPA representatives discuss the possibilities of a standard and the form it might take with members of the National Air Pollution Control Techniques Advisory Committee. Industry representatives and other interested parties also participate in these meetings.

The information acquired in the project is summarized in the Background Information Document (BID). The BID, the standard, and a preamble explaining the standard are widely circulated to the industry being considered for control, environmental groups, other government agencies, and offices within EPA. Through this extensive review process, the points of view of expert reviewers are taken into consideration as changes are made to the documentation.

A "proposal package" is assembled and sent through the offices of EPA Assistant Administrators for concurrence before the proposed standard is officially endorsed by the EPA Administrator. After being approved by the EPA Administrator, the preamble and the proposed regulation are published in the Federal Register.

As a part of the Federal Register announcement of the proposed regulation, the public is invited to participate in the standard-setting process. EPA invites written comments on the proposal and also holds a public hearing to discuss the proposed standard with interested parties. All public comments are summarized and incorporated into a second volume of the BID. All information reviewed and generated in studies in support of the standard of performance is available to the public in a "docket" on file in Washington, D. C.

Comments from the public are evaluated, and the standard of performance may be altered in response to the comments.

The significant comments and EPA's position on the issues raised are included in the "preamble" of a "promulgation package," which also contains the draft of the final regulation. The regulation is then subjected to another round of review and refinement until it is approved by the EPA Administrator. After the Administrator signs the regulation, it is published as a "final rule" in the Federal Register.

2.4 CONSIDERATION OF COSTS

Section 317 of the Act requires an economic impact assessment with respect to any standard of performance established under Section 111 of the Act. The assessment is required to contain an analysis of: (1) the costs of compliance with the regulation, including the extent to which the cost of compliance varies depending on the effective date of the regulation and the development of less expensive or more efficient methods of compliance; (2) the potential inflationary or recessionary effects of the regulation; (3) the effects the regulation might have on small business with respect to competition; (4) the effects of the regulation on consumer costs; and (5) the effects of the regulation on energy use. Section 317 also requires that the economic impact assessment be as extensive as practicable.

The economic impact of a proposed standard upon an industry is usually addressed both in absolute terms and in terms of the control costs that would be incurred as a result of compliance with typical, existing State control regulations. An incremental approach is necessary because both new and existing plants would be required to comply with State regulations in the absence of a Federal standard of performance. This approach requires a detailed analysis of the economic impact from the cost differential that would exist between a proposed standard of performance and the typical State standard.

Air pollutant emissions may cause water pollution problems, and captured potential air pollutants may pose a solid waste disposal problem. The total environmental impact of an emission source must, therefore, be analyzed and the costs determined whenever possible.

A thorough study of the profitability and price-setting mechanisms of the industry is essential to the analysis so that an accurate estimate of potential adverse economic impacts can be made for proposed standards. It is also essential to know the capital requirements for pollution control systems already placed on plants so that the additional capital requirements necessitated by these Federal standards can be placed in proper perspective. Finally, it is necessary to assess the availability of capital to provide the additional control equipment needed to meet the standards of performance.

2.5 CONSIDERATION OF ENVIRONMENTAL IMPACTS

Section 102(2)(C) of the National Environmental Policy Act (NEPA) of 1969 requires Federal agencies to prepare detailed environmental impact statements on proposals for legislation and other major Federal actions significantly affecting the quality of the human environment. The objective of NEPA is to build into the decisionmaking process of Federal agencies a careful consideration of all environmental aspects of proposed actions.

In a number of legal challenges to standards of performance for various industries, the United States Court of Appeals for the District of Columbia Circuit has held that environmental impact statements need not be prepared by the Agency for proposed actions under Section 111 of the Clean Air Act. Essentially, the Court of Appeals has determined that the best system of emission reduction requires the Administrator to take into account counter-productive environmental effects of a proposed standard, as well as economic costs to the industry. On this basis, therefore, the Court established a narrow exemption from NEPA for EPA determination under Section 111.

In addition to these judicial determinations, the Energy Supply and Environmental Coordination Act (ESECA) of 1974 (PL-93-319) specifically exempted proposed actions under the Clean Air Act from NEPA requirements. According to Section 7(c)(1), "No action taken under the Clean Air Act shall be deemed a major Federal action significantly affecting the quality of the human environment within the meaning of the National Environmental Policy Act of 1969" (15 U.S.C. 793(c)(1)).

Nevertheless, the Agency has concluded that the preparation of environmental impact statements could have beneficial effects on certain regulatory actions. Consequently, although not legally required to do so by Section 102(2)(C) of NEPA, EPA has adopted a policy requiring that environmental impact statements be prepared for various regulatory actions, including standards of performance developed under Section 111 of the Act. This voluntary preparation of environmental impact statements, however, in no way legally subjects the Agency to NEPA requirements.

To implement this policy, a separate section in this document is devoted solely to an analysis of the potential environmental impacts associated with the proposed standards. Both adverse and beneficial impacts in such areas as air and water pollution, increased solid waste disposal, and increased energy consumption are discussed.

2.6 IMPACT ON EXISTING SOURCES

Section 111 of the Act defines a new source as ". . . any stationary source, the construction or modification of which is commenced . . ." after the proposed standards are published. An existing source is redefined as a new source if "modified" or "reconstructed" as defined in amendments to the general provisions of Subpart A of 40 CFR Part 60, which were promulgated in the Federal Register on December 16, 1975 (40 FR 58416).

Promulgation of a standard of performance requires States to establish standards of performance for existing sources in the same industry under Section 111 (d) of the Act if the standard for new sources limits emissions of a designated pollutant (i.e., a pollutant for which air quality criteria have not been issued under Section 108 or which has not been listed as a hazardous pollutant under Section 112). If a State does not act, EPA must establish such standards. General provisions outlining procedures for control of existing sources under Section 111(d) were promulgated on November 17, 1975, as Subpart B of 40 CFR Part 60 (40 FR 53340).

2.7 REVISION OF STANDARDS OF PERFORMANCE

Congress was aware that the level of air pollution control achievable by any industry may improve with technological advances. Accordingly, section 111 of the Act provides that the Administrator ". . . shall, at least every 4 years, review and, if appropriate, revise . . ." the standards. Revisions are made to assure that the standards continue to reflect the best systems that become available in the future. Such revisions will not be retroactive, but will apply to stationary sources constructed or modified after the proposal of the revised standards.

3.0 SOURCES OF VOC EMISSIONS

3.1 GENERAL

Natural gas processing plants are a part of the oil and gas industry. Field gas is first gathered in the field directly from gas wells or from oil/gas separation equipment (see Figure 3-1). The gas may be compressed at field stations for the purpose of transporting it to treating or processing facilities. Treating is necessary in certain instances for removal of water, sulfur compounds, or carbon dioxide. Gas gathering, compression, and treating may or may not occur at a gas plant. For the purposes of this document, natural gas processing plants are defined as facilities engaged in the separation of natural gas liquids from field gas and/or fractionation of the liquids into natural gas products, such as ethane, propane, butane, and natural gasoline. Types of gas plants are: absorption, refrigerated absorption, refrigeration, compression, adsorption, cryogenic — Joule-Thomson, and cryogenic-expander.[1]

3.2 DESCRIPTION OF FUGITIVE EMISSION SOURCES

In this document, fugitive emissions from gas plants are considered to be those volatile organic compound (VOC) emissions that result when process fluid (either gaseous or liquid) leaks from plant equipment. VOC emissions are defined as nonmethane-nonethane hydrocarbon emissions. There are many potential sources of fugitive emissions in a gas plant. The following sources are considered in this chapter: pumps, compressors, valves, relief valves, open-ended lines, sampling connections, flanges and connections, and gas-operated control valves. These source types are described below.

3.2.1 Pumps

Pumps are used in gas plants for the movement of natural gas liquids. The centrifugal pump is the most widely used pump. However, other types, such as the positive-displacement, reciprocating and rotary action, and special canned and diaphragm pumps, may also be used. Natural gas liquids

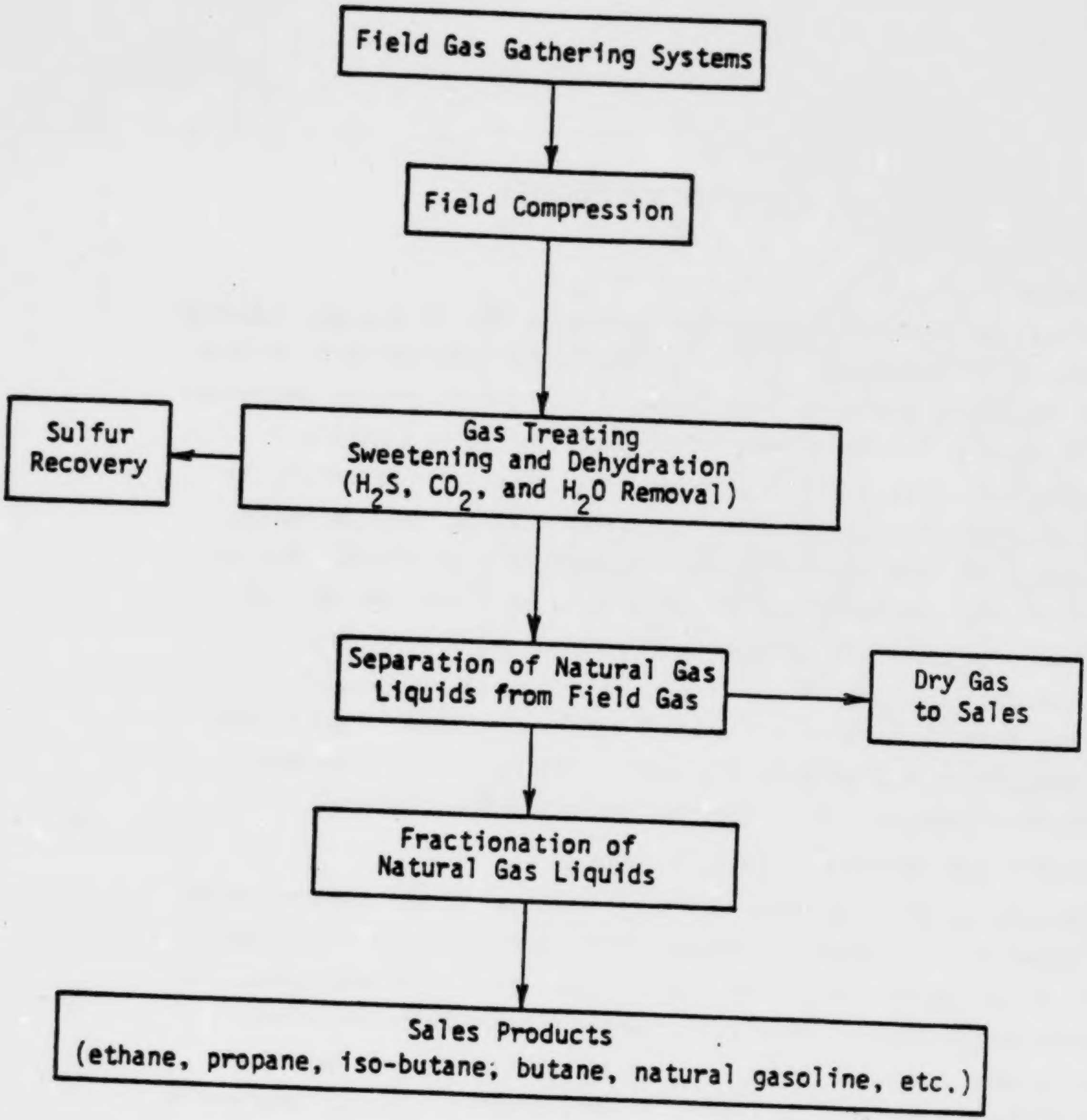
Field Gas Gathering Systems
Field Compression
Sulfur Recovery
Gas Treating
Sweetening and Dehydration
(H_2S, CO_2, and H_2O Removal)
Separation of Natural Gas Liquids from Field Gas
Dry Gas to Sales
Fractionation of Natural Gas Liquids
Sales Products
(ethane, propane, iso-butane, butane, natural gasoline, etc.)

Figure 3-1. General Schematic of Natural Gas-Gasoline Processing.

transferred by pumps can leak at the point of contact between the moving shaft and stationary casing. Consequently, all pumps except the canned-motor and diaphragm type require a seal at the point where the shaft penetrates the housing in order to isolate the pump's interior from the atmosphere.

Two generic types of seals, packed and mechanical, are currently in use on pumps. Packed seals can be used on both reciprocating and rotary action types of pumps. As Figure 3-2 shows, a packed seal consists of a cavity ("stuffing box") in the pump casing filled with special packing material that is compressed with a packing gland to form a seal around the shaft. Lubrication is required to prevent the buildup of frictional heat between the seal and shaft. The necessary lubrication is provided by a lubricant that flows between the packing and the shaft.[2]

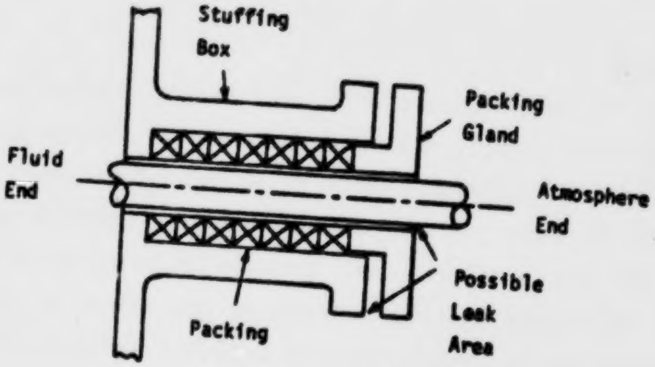

Figure 3-2. Diagram of a simple packed seal.[2]

Mechanical seals are limited in application to pumps with rotating shafts and can further be categorized as single and dual mechanical seals. There are many variations to the basic design of mechanical seals, but all have a lapped seal face between a stationary element and a rotating seal ring. In a single mechanical seal application (Figure 3-3), the rotating-seal ring and stationary element faces are lapped to a very high degree of flatness to maintain contact throughout their entire mutual surface area. As with a packed seal, the seal faces must be lubricated to remove frictional heat. However, because of its construction, much less lubricant is needed.

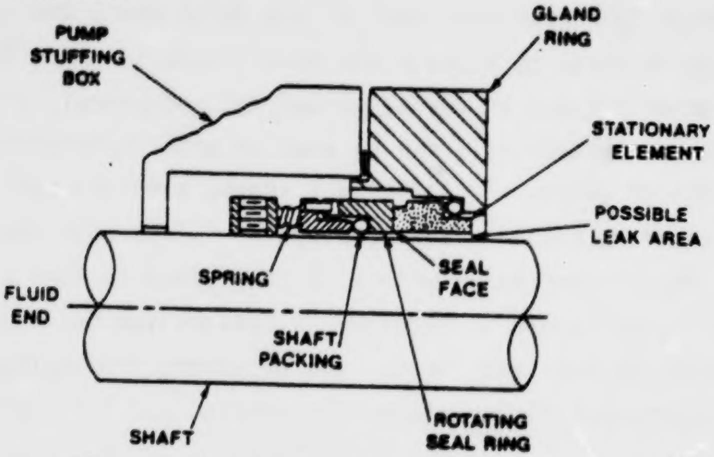

Figure 3-3. Diagram of a basic single mechanical seal.[2]

3.2.2 Compressors

Three types of compressors can be used in the natural gas production industry: centrifugal, reciprocating, and rotary. The centrifugal compressor utilizes a rotating element or series of elements containing curved blades to increase the pressure of a gas by centrifugal force. Reciprocating and rotary compressors increase pressure by confining the gas in a cavity and progressively decreasing the volume of the cavity. Reciprocating compressors usually employ a piston and cylinder arrangement while rotary compressors utilize rotating elements such as lobed impellers or sliding vanes. About half of the compressors installed in new plants are likely to be centrifugal and half reciprocating.

As with pumps, sealing devices are required to prevent leakage from compressors. Rotary shaft seals for compressors may be chosen from several different types: labyrinth, restrictive carbon rings, mechanical contact, and liquid film. All of these seal types are leak restriction devices; none of them completely eliminate leakage. Many compressors may be equipped with ports in the seal area to evacuate collected gases. Mechanical contact seals are a common type of seal for rotary compressor shafts, and are similar to the mechanical seals described for pumps. In this type of seal the clearance between the rotating and stationary elements is reduced to zero. Oil or another suitable lubricant is supplied to the seal faces. Mechanical seals can achieve the lowest leak rates of the types identified above, but they are not suitable for all processing conditions.[3]

Packed seals are used for reciprocating compressor shafts. As with pumps, the packing in the stuffing box is compressed with a gland to form a seal. Packing used on reciprocating compressor shafts is often of the "chevron" or nested V type.[4] Because of safety considerations, the area between the compressor seals and the compressor motor (distance piece) is normally enclosed and vented outside of the compressor building. If hydrogen sulfide is present in the gas, then the vented vapors are normally flared.[10]

Reciprocating compressors may employ a metallic packing plate and nonmetallic partially compressible (i.e, GRAFFOIL,[R] TEFLON[R]) material or oil wiper rings to seal shaft leakage to the distance piece. Nevertheless, some leakage into the distance piece may occur.

3.2.3 Process Valves

One of the most common pieces of equipment in gas plants is the valve. The types of valves commonly used are globe, gate, plug, ball, butterfly, relief, and check valves. All except the relief valve (to be discussed below) and check valve are activated through a valve stem, which may have a rotational or linear motion, depending on the specific design. This stem requires a seal to isolate the process fluid inside the valve from the atmosphere as illustrated by the diagram of a gate valve in Figure 3-4. The possibility of a leak through this seal makes it a potential source of fugitive emissions. Since a check valve has no stem or subsequent packing gland, it is not considered to be a potential source of fugitive emissions.

Sealing of the stem to prevent leakage can be achieved by packing inside a packing gland or O-ring seals. Valves that require the stem to move in and out with or without rotation must utilize a packing gland. Conventional packing glands are suited for a wide variety of packing materials. The most common are various types of braided asbestos that contain lubricants. Other packing materials include graphite, graphite-impregnated fibers, and tetrafluoroethylene polymer. The packing material used depends on the valve application and configuraton.[6] These conventional packing glands can be used over a wide range of operating temperatures. At high pressures these glands must be quite tight to attain a good seal.[7]

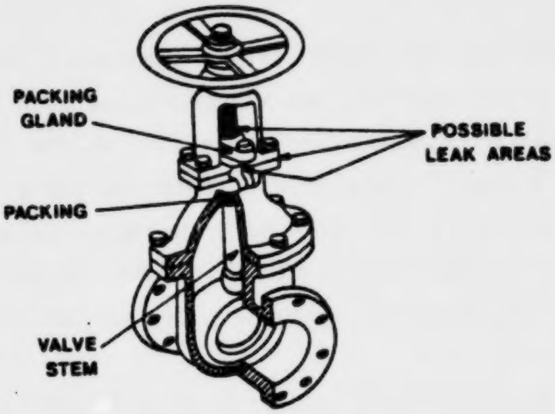
PACKING
GLAND
POSSIBLE
LEAK AREAS
PACKING
VALVE
STEM

Figure 3-4. Diagram of a gate valve.[2]

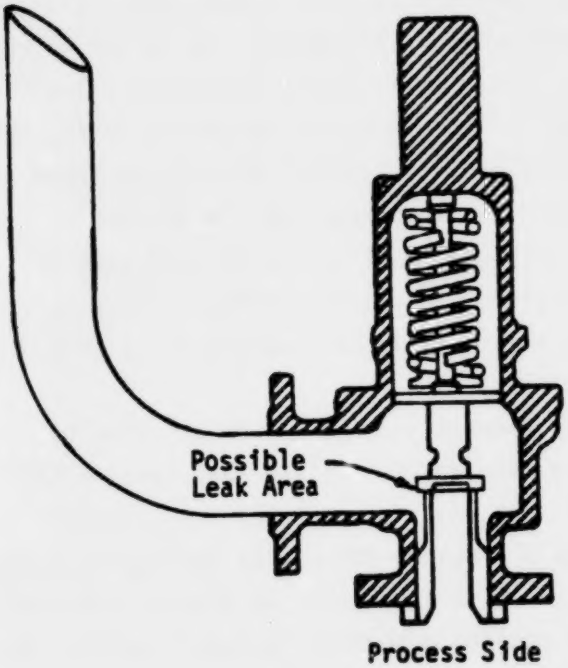
Possible
Leak Area
Process Side

Figure 3-5. Diagram of a spring-loaded relief valve.

3.2.4 Pressure Relief Devices

Engineering codes require that pressure-relieving devices or systems be used in applications where the process pressure may exceed the maximum allowable working pressure of the vessel. The most common type of pressure-relieving device used in process units is the pressure relief valve (Figure 3-5). Typically, relief valves are spring-loaded and designed to open when the process pressure exceeds a set pressure, allowing the release of vapors or liquids until the system pressure is reduced to its normal operating level. When the normal pressure is reattained, the valve reseats, and a seal is again formed.[8] The seal is a disk on a seat, and the possibility of a leak through this seal makes the pressure relief valve a potential source of VOC fugitive emissions. A seal leak can result from corrosion or from improper reseating of the valve after a relieving operation.[2]

Rupture disks may also be used in process units. These disks are made of a material that ruptures when a set pressure is exceeded, thus allowing the system to depressurize. The advantage of a rupture disk is that the disk seals tightly and does not allow any VOC to escape from the system under normal operation. However, when the disk does rupture, the system depressurizes until atmospheric conditions are obtained, unless the disk is used in series with a pressure relief valve.

3.2.5 Open-Ended Lines

Some valves are installed in a system so that they function with the downstream line open to the atmosphere. Open-ended lines are used mainly in intermittent service for sampling and venting. Examples are purge, drain, and sampling lines. Some open-ended lines are needed to preserve product purity. These are normally installed between multi-use product lines to prevent products from collecting in cross-tie lines due to valve seat leakage. In addition to valve seat leakage, an incompletely closed valve could result in VOC emissions to the atmosphere.

3.2.6 Flanges and Connections

Flanges are bolted, gasket-sealed junctions used wherever pipe or other equipment such as vessels, pumps, valves, and heat exchangers may require isolation or removal. Connections are all other nonwelded fittings that serve a similar purpose to flanges, that also allow bends in pipes (ells), joining two pipes (couplings), or joining three or four pipes (tees or crosses). The connections are typically threaded.

Flanges may become fugitive emission sources when leakage occurs due to improperly chosen gaskets or poorly assembled flanges. The primary cause of flange leakage is due to thermal stress that piping or flanges in some services undergo; this results in the deformation of the seal between the flange faces.[9] Threaded connections may leak if the threads become damaged or corroded, or if tightened without sufficient lubrication or torque.

3.2.7 Gas-Operated Control Valves

Pneumatic control valves are used widely in process control at gas plants. Typically, compressed air is used as the operating medium for these control valves. In certain instances, however, field gas or flash gas is used to supply pressure.[5] Since gas is either continuously bled to the atmosphere or is bled each time the valve is activated, this can potentially be a large source of fugitive emissions. There are also some instances where highly pressurized field gas is used as the operating medium for emergency control valves. However, these valves are seldom activated and, therefore, have a much lower emissions potential than control valves in routine service.

3.2.8 Sampling Connections

The operation of a gas plant is checked periodically by routine analyses of process fluids. To obtain representative samples for these analyses, sampling lines must first be purged prior to sampling. The purged liquid is sometimes drained onto the ground or into a drain, where it can evaporate and release VOC emissions to the atmosphere. Purged vapor is typically released directly to the atmosphere.

3.3 BASELINE FUGITIVE VOC EMISSIONS

Baseline fugitive emission data have been obtained at six natural gas/gasoline processing plants. Two of the plants were tested by Rockwell International under contract to the American Petroleum Institute,[11] and four plants were tested by Radian Corporation under contract to EPA.[12] Baseline fugitive emission factors for six of the seven component types were developed from these data.[12] The emission factors are presented in Table 3-1. The factors represent the average baseline emission rate from each of the components of a specific type in a gas plant. Baseline emissions for sampling connections were determined based on purge volume calculations for both gas and liquid streams.[13,14] The compressor seal

Table 3-1. BASELINE FUGITIVE EMISSION FACTORS FOR GAS PLANTS, kg/day

Component	Emission factor		95% Confidence interval	
Valves[a]	0.18	(0.48)	0.1-0.3	(0.2-1)
Relief valves[a]	0.33	(4.5)	0.007-8	(0.1-100)
Open-ended lines[a]	0.34	(0.53)	0.1-0.7	(0.2-1)
Compressor seals[a,c]	1.0	(4.9)	0.1-5	(0.7-30)
Pump seals[a]	1.2	(1.5)	0.5-3	(0.5-4)
Sampling connections[b]				
Gas	0.016	(0.32)		
Liquid	0.085	(0.085)		
Flanges and connections[a]	0.011	(0.026)	0.006-0.02	(0.01-0.05)

xx = VOC emission values.
(xx)= Total hydrocarbon emission values.

[a] Reference 12.

[b] References 13 and 14. Liquid streams are assumed to be 100 percent VOC, sampled twice per month with a 1.96 liter purge. Gas streams are assumed to be sampled twice per shift with a 1 sec purge through a 6.4 mm ID sample tube 15 cm long; 80% methane, 15% ethane, 5% VOC.

[c] Emission factors for compressors are based on EPA and API testing of emissions into the distance piece area from open frame compressors. The factors do not include emissions into the seal packing vent or into enclosed distance pieces. Therefore, the emission factors given are probably understated substantially.[16]

emissions factor represents only the emissions measured in the distance piece area from open frame compressors. Therefore, the emissions from the seal packing vent and from enclosed distance pieces are not included. This probably results in a significant understatement of total compressor emissions because the majority of the compressor emissions will come from the seal vents.[16] The total daily and annual emissions from fugitive sources at a model gas plant are shown in Table 3-2. Total daily emissions are calculated by multiplying the number of pieces of each type of equipment by the corresponding daily emission factor. The average percent of total emissions attributed to each component type is also presented in Table 3-2.

Table 3-2. ESTIMATED BASELINE FUGITIVE VOC EMISSIONS FROM A TYPICAL GAS PLANT

Component type	Number of components	Baseline emissions,[a] kg/day	Percentage of total emissions
Valves	750	140 (360)	58 (59)
Relief valves	12	4.0 (54)	2 (9)
Open-ended lines	150	51 (80)	21 (13)
Compressor seals[b]	6	6.0 (29)	2 (5)
Pump seals	6	7.2 (9.0)	3 (1)
Sampling connections			
Inlet Gas	6	0.1 (1.9)	1 (1)
Liquids	6	0.5 (0.5)	1 (1)
Flanges and connections	3,000	33 (78)	14 (13)
Total baseline emissions		242 (612)	

xx = VOC emission values.
(xx) = Total hydrocarbon emissions values.

[a] From Table 3-1.

[b] As discussed in Table 3-1, the compressor seal emission factor and thus the percentage of total emissions from compressors may be substantially understated.

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4.0 EMISSION CONTROL TECHNIQUES

4.1 INTRODUCTION

Sources of fugitive VOC emissions from gas plant equipment were identified in Chapter 3 of this document. This chapter discusses the emission control techniques that can be applied to reduce fugitive VOC emissions from these sources. These techniques include leak detection and repair programs and equipment specifications. The estimated control effectiveness of the techniques is also presented. In some cases, the techniques for reducing gas plant fugitive emissions are based on transfer of control technology as applied to related industries. This approach is possible because the related industries (e.g., refineries) use similar types of equipment, such as valves, pumps, and compressors. There may be differences between gas plants and related industries in average line temperatures, product composition, or other parameters. However, these differences do not influence the applicability of the techniques used in controlling fugitive emissions.

Chapter 4 also presents other control strategies applicable to control of fugitive emissions from gas plants. However, the control effectiveness of these alternative strategies has not been estimated.

4.2 LEAK DETECTION AND REPAIR METHODS

Leak detection and repair methods can be applied in order to reduce fugitive emissions from gas plant sources. Leak detection methods are used to identify equipment components that are emitting significant amounts of VOC. Emissions from leaking sources may be reduced by three general methods: repair, modification, or replacement of the source.

4.2.1 Leak Detection Techniques

Various monitoring techniques that can be used in a leak detection program include individual component surveys, unit area (walk-through) surveys, and fixed-point monitoring systems. These emission detection methods would yield qualitative indications of leaks.

4.2.1.1 Individual Component Survey. Each fugitive emission source (pump, valve, compressor, etc.) is checked for VOC leakage in an individual component survey. The source may be checked for leakage by visual, audible, olfactory, soap solution, or instrument techniques. Visual methods are good for locating liquid leaks, especially pump seal failures. High pressure vapor leaks may be detected by hearing the escaping vapors, and leaks of odorous materials may be detected by smell. Predominant industry practices are leak detection by visual, audible, and olfactory methods. However, in many instances, even very large VOC leaks are not detected by these methods.

Applying a soap solution on equipment components is one individual survey method. If bubbles are seen in the soap solution, a leak from the component is indicated. The method requires that the observer subjectively determine the rate of leakage based on the rate of formation of soap bubbles over a specified time period. The method is not appropriate for very hot sources, although ethylene glycol can be added to the soap solution to extend the temperature range. This method is also not suited for moving shafts on pumps or compressors, since the motion of the shaft may cause entrainment of air in the soap solution and indicate a leak when none is present. In addition, the method cannot generally be applied to open sources such as relief valves or vents without additional equipment.

The use of portable hydrocarbon detection instruments is the best known individual survey method for identifying leaks of VOC from equipment components because it is applicable to all types of sources. The instrument is used to sample and analyze the air in close proximity to the potential leak surface by traversing the sampling probe tip over the entire area where leaks may occur. This sampling traverse is called "monitoring" in subsequent descriptions. A measure of the hydrocarbon concentration of the sampled air is displayed in the instrument meter. The performance criteria for monitoring instruments and a description of instrument survey methods are included in Appendix D. Table 4-1 presents data on the percentage of components that are

Table 4-1. PERCENTAGE OF COMPONENTS PREDICTED TO BE LEAKING IN AN INDIVIDUAL COMPONENT SURVEY

Component type	Predicted percent of sources leaking				
	100,000 ppmv	50,000 ppmv	20,000 ppmv	10,000 ppmv	1,000 ppmv
Valves[a]	9	11	14	18	28
Relief valves[b]	8	11	15	19	34
Compressor seals[a]	20	27	35	43	60
Pump seals[a]	10	22	26	33	53

[a] Reference 1.

[b] Reference 2.

predicted to have instrument readings greater than or equal to various concentrations during an individual component survey.

4.2.1.2 Unit Area Survey. A unit area or walk-through survey entails measuring the ambient VOC concentration within a given distance, for example, one meter, of all equipment located at ground level and other accessible levels within a processing area. These measurements are performed with a portable VOC detection instrument utilizing a strip chart recorder.

The instrument operator walks a predetermined path to assure total coverage of a unit on both the upwind and downwind sides of the equipment, noting on the chart record the location in a unit where any elevated VOC concentrations are detected. If an elevated VOC concentration is recorded, the components in that area can be screened individually to locate the specific leaking equipment.

It is estimated that 50 percent of all significant leaks in a unit are detected by the walk-through survey, provided that there are only a few pieces of leaking equipment, thus reducing the VOC background concentration sufficiently to allow for reliable detection.[3]

The major advantages of the unit area survey are that leaks from accessible leak sources near the ground can be located quickly and that the leak detection manpower requirements can be lower than those for the individual component survey. Some of the shortcomings of this method are that VOC emissions from adjacent units can cause false leak indications; high or intermittent winds (local meteorological conditions) can increase dispersion of VOC, causing leaks to be undetected; elevated equipment leaks may not be detected; and additional effort is necessary to locate the specific leaking equipment, i.e., individual checks in areas where high concentrations are found.

4.2.1.3 Fixed-Point Monitors. This method consists of placing several automatic hydrocarbon sampling and analysis instruments at various locations in the process unit. The instruments may sample the ambient air intermittently or continuously. Hydrocarbon concentrations above a background level indicate a leaking component. As in the walk-through method, an individual component survey is required to identify the specific leaking component in the area. Leaks from adjacent units and meteorological conditions may affect the results obtained. The efficiency of this method is not well established, but it has been estimated that 33 percent of the number of leaks identified by a complete individual component survey could be located by fixed-point monitors.[4] These leaks would be detected sooner by fixed-point monitors than by use of portable monitors, because the fixed-point monitors operate semi continuously. Fixed-point monitors are more expensive; multiple fixed point monitors may be required; and use of the portable instrument is still required to locate the specific leaking component. Calibration and maintenance costs may be higher. Fixed-point monitors have been used to detect emissions of hazardous or toxic substances (such as vinyl chloride) as well as potentially explosive conditions. Fixed-point monitors have an advantage in these cases, since a particular compound can be selected as the sampling criterion.

4.2.1.4 Visual Inspections. Visual inspections can be performed for any of the leak detection techniques discussed above to detect evidence of liquid leakage from plant equipment. When such evidence is observed, the operator can use a portable VOC detection instrument to measure the VOC concentration of the source. In a specific application, visual inspections can be used to detect the failure of the outer seal of a pump's dual mechanical seal system. Observation of liquid leaking along the shaft indicates an outer seal failure and signals the need for seal repair.[5]

4.2.2 Repair Methods

The following descriptions of repair methods include only those features of each fugitive emission source (pump, valve, etc.) that should be considered in assessing the applicability and effectiveness of each method.

4.2.2.1 Valves. Most valves have a packing gland that can be tightened while in service. Although this procedure should decrease the emissions from the valve, in some cases it may actually increase the emission rate if the packing is old and brittle or has been overtightened. Unbalanced tightening of the packing gland may also cause the packing material to be positioned improperly in the valve and allow leakage. Valves that are not often used can build up a "static" seal of paint or hardened lubricant that could be broken by tightening the packing gland. Plug-type valves can be lubricated with grease to reduce emissions around the plug.

Some types of valves have no means of in-service repair and must be isolated from the process and removed for repair or replacement. Other valves, such as control valves, may be excluded from in-service repair by operating procedures or safety procedures. In many cases, valves cannot be isolated from the process for removal. If a line must be shut down in order to isolate a leaking valve, the emissions resulting from the shutdown may possibly be greater than the emissions from the valve if it were allowed to leak until the next process change that permits isolation for repair. Depending on site-specific factors, it may also be possible to repair leaking process valves by injection of a sealing fluid into the source of the leak.[6]

4.2.2.2 Pressure Relief Valves. In general, pressure relief valves that leak must be removed in order to repair the leak. In some cases of improper reseating, manual release of the valve may improve the seat seal. In order to remove the pressure relief valve for repair without shutting down the process, the process must be kept isolated from atmosphere. The safest way to isolate the process is to install a three-way valve with parallel relief systems so that one of the two relief systems is always open.[7,8]

4.2.2.3 Compressor Seals. Leaks from centrifugal and reciprocating compressor seals may be reduced by replacing the seal or tightening or replacing the packing. If the leak is small, temporary emissions resulting from a shutdown may be greater than the emissions from the leaking seal. It is anticipated that for many reciprocating compressor seals it will not be possible to bring leaks under the designated action level. In addition, there will not often be a spare compressor to allow shutdown for repair of the leaking compressor seal. In these instances it would be more appropriate to vent leaks from compressor seals to a control device. This approach is described in Section 4.3.2.

4.2.2.4 Pumps. In some cases, it is possible to operate a spare pump while the leaking pump is being repaired. Leaks from packed seals may be reduced by tightening the packing gland. At some point, the packing may deteriorate to the point where further tightening would have no effect or possibly even increase fugitive emissions from the seal. The packing can be replaced with the pump out of service. When mechanical seals are utilized, the pump must be dismantled so the leaking seal can be repaired or replaced. Dismantling pumps may result in spillage of some process fluid causing emissions of VOC. These temporary emissions have the potential of being greater than the continued leak from the seal. Therefore, the pump should be isolated from the process and flushed of VOC as much as possible prior to repacking or seal replacement.

4.2.2.5 Flanges and Connections. In some cases, leaks from flanges can be reduced by replacing the flange gaskets. Leaks from small threaded connections can be reduced by placing synthetic (e.g., Teflon) tape or "pipe dope" on the male threads before the connection is made. Most flanges and connections cannot be isolated to permit repair of leaks. Data show that flanges and connections emit relatively small amounts of VOC (Table 3-1).

4.2.3 Emission Control Effectiveness of Leak Detection and Repair

The control efficiency achieved by a leak detection and repair program is dependent on several factors, including the leak definition, inspection interval, and the allowable repair time.

4.2.3.1 Definition of a Leak. The first step in developing a monitoring plan for fugitive VOC emissions is to define an instrument meter reading that is indicative of an equipment leak. The choice of the meter reading for defining a leak is influenced by several considerations. The percent of total mass emissions that can potentially be controlled by the leak detection and repair program can be affected by varying the leak definition. Table 4-2 gives the percent of total mass emissions affected at various leak definitions for a number of component types. From the table, it can be seen that, in general, a low leak definition results in larger potential emission reductions.

Other considerations are more source specific. For valves, the selection of an action level for defining a leak is a tradeoff between the desire to locate all significant leaks and to ensure that emission reductions are possible through maintenance. Although test data show that some valves with meter readings less than 10,000 ppm have significant emission rates, most of the major emitters have meter readings greater

Table 4-2. PERCENT OF TOTAL EMISSIONS AFFECTED AT VARIOUS LEAK DEFINITIONS

	Percent of mass emissions affected at this leak definition[a]				
Component type	100,000 ppmv	50,000 ppmv	20,000 ppmv	10,000 ppmv	1,000 ppmv
Valves[b]	54 (59)	64 (70)	78 (83)	86 (87)	97 (98)
Relief valves[c]	41 (42)	53 (56)	67 (69)	77 (77)	96 (96)
Compressor seals[b]	63 (64)	75 (76)	87 (88)	92 (93)	99 (99)
Pump seals[b]	46 (47)	63 (63)	72 (71)	79 (79)	94 (94)

xx = VOC emission values.
(xx) = Total hydrocarbon emission values.

[a] These figures relate the leak definition to the percentage of total mass emissions that can be expected from sources with concentrations at the source greater than the leak definition. If these sources were instantaneously repaired to a zero leak rate and no new leaks occurred, then emissions could be expected to be reduced by this maximum theoretical efficiency.

[b] Reference 1.

[c] Reference 2.

than 10,000 ppm. Maintenance programs on valves have shown that emission reductions are possible through on-line repair for essentially all valves with nonzero meter readings. There are, however, cases where on-line repair attempts result in an increased emission rate. The increased emissions from such a source could be greater than the emission reduction if maintenance is attempted on low leak valves. These valves should, however, be able to achieve essentially 100 percent emission reduction through off-line repair. Generally, the emission rates from valves with meter readings greater than or equal to 10,000 ppm are significant enough so that an overall emission reduction is likely for a leak detection and repair program with a 10,000 ppm leak definition. In addition, testing by EPA and industry has shown that meter readings will generally be either much less than 10,000 ppm or much greater than 10,000 ppm.[1,9,10] Therefore, 10,000 ppm was determined to be the most reasonable leak definition to initiate valve maintenance efforts while still having confidence that an overall emission reduction will result.

For pump and compressor seals, the rationale for selection of an action level is different because the cause of leakage is different. As opposed to valves, which generally have zero leakage, most pump and compressor seals leak to a certain extent while operating normally. These seals would tend to have low instrument meter readings. With time, however, as the seal begins to wear, the concentration and emission rate are likely to increase. At any time, catastrophic seal failure can occur with a large increase in the instrument meter reading and emission rate. As shown in Table 4-2, over 90 percent of the emissions from compressor seals and 80 percent of the emissions from pump seals are from sources with instrument meter readings greater than or equal to 10,000 ppm. Since properly designed, installed, and operated seals should have low instrument meter readings, and, since the bulk of the pump and compressor seal emissions are from seals that have worn out or failed such that they have a concentration equal to or greater than 10,000 ppm, this level was chosen as a reasonable action level.

4.2.3.2 Inspection Interval. The length of time between inspections should depend on the expected occurrence and recurrence of leaks after a piece of equipment has been checked and/or repaired. This interval can be related to the type of equipment and service conditions, and different intervals can be specified for different pieces of equipment. Monitoring may be scheduled on an annual, quarterly, monthly, or weekly basis. The choice of the interval affects the emission reduction achievable, since more frequent inspection intervals will result in earlier detection and repair of leaking sources.

4.2.3.3 Allowable Repair Time. If a leak is detected, the equipment should be repaired within a certain time period. The allowable repair time should allow the plant operator sufficient time to obtain necessary repair parts and maintain some degree of flexibility in overall plant maintenance scheduling. The determination of this allowable repair time will affect emission reductions by influencing the length of time that leaking sources are allowed to continue to emit VOC.

4.2.3.4 Estimation of Reduction Efficiency. Data are presented in Table 4-2 that show the expected percent of total emissions from each type of source contributed by those sources with VOC concentrations greater than given leak definitions. If a leak detection and repair program resulted in repair of all such sources to 0 ppmv, elimination of all sources over the leak definition between inspections, and instantaneous repair of those sources found at each inspection, then emissions could be expected to be reduced by the amount reported in Table 4-2. However, since these conditions are not met in practice, the fraction of emissions from sources with VOC concentrations over the leak definition represents the theoretical maximum reduction efficiency. The approach used to estimate emission reductions presented here is to reduce this theoretical maximum control efficiency by accounting quantitatively for those factors outlined above.

There are two models available for estimation of emission reduction efficiency from leak detection and repair programs. Both models are used in this BID. The first model (the computer leak detection and repair (LDAR) model) is described in Appendix E and is applied to valves and pumps. It is the preferred model, because it incorporates recently available data on leak occurrence and recurrence and data on the effectiveness of simple in-line repair. These data are not available for relief valves and compressors. Therefore, a second model (the ABCD model) is applied to these sources. The ABCD model can be expressed mathematically by the following equation:[11]

Reduction efficiency = A x B x C x D

Where:

A = Theoretical Maximum Control Efficiency = fraction of total mass emissions from sources with VOC concentrations greater than the leak definition (from Table 4-2).

B = Leak Occurrence and Recurrence Correction Factor = correction factor to account for sources which start to leak between inspections (occurrence), for sources which are found to be leaking, are repaired and start to leak again before the next inspection (recurrence), and for known leaks that could not be repaired.

C = Noninstantaneous Repair Correction Factor = correction factor to account for emissions which occur between detection of a leak and subsequent repair, since repair is not instantaneous.

D = Imperfect Repair Correction Factor = correction factor to account for the fact that some sources which are repaired are not reduced to zero. For computational purposes, all sources which are repaired are assumed to be reduced to an emission level equivalent to a concentration of 1,000 ppmv.

As an example of this technique, Table 4-3 gives values for the "B," "C," and "D" correction factors for various possible inspection intervals, allowable repair times, and leak definitions. These values are given only for relief valves and compressors seals, because the reduction efficiency for valves and pump seals is estimated according to the LDAR model presented in Appendix E.

The ABCD model control efficiencies for compressors and pressure relief valves, however, have been modified to correct for the accuracy of the engineering judgment employed to derive one of the model inputs. The accuracy of the judgment was approximated by the comparison of the LDAR model and ABCD model control efficiencies for valves. The control efficiency for compressors and pressure relief valves was derived by weighting the ABCD model results by this relationship.[18] This technique is used to determine emission reductions for control alternatives in Table 7-1.

Table 4-3. VOC EMISSION CORRECTION FACTORS FOR VARIOUS INSPECTION INTERVALS, ALLOWABLE REPAIR TIMES, AND LEAK DEFINITIONS FOR ABCD MODEL

	Leak occurence and recurrence correction factor[a]		Non-instantaneous repair correction factor[b]		Imperfect repair correction factor[c]			
	Inspection interval		Allowable repair time (days)		Leak definition (ppmv)			
Component type	Quarterly	Monthly	15	5	100,000	50,000	10,000	1,000
Relief valves	0.90	0.95	0.98	0.99	0.92 (0.99)	0.91 (0.99)	0.89 (0.99)	0.85 (0.99)
Compressor seals	0.90	0.95	0.98	0.99	0.98 (0.97)	0.98 (0.96)	0.97 (0.95)	0.97 (0.94)

xx = VOC emission values.

(xx) = Total hydrocarbon emission values.

[a] Factor accounts for sources that start to leak between inspections (occurrence), for sources that are found to be leaking, are repaired, and start to leak again before the next inspection (recurrence), and for leaking sources that cannot be repaired. Reference 11.

[b] Factor accounts for emissions that occur between detection of a leak and subsequent repair. Reference 11.

[c] Factors accounts for the fact that some sources that are repaired are not reduced to zero. Repaired sources are assumed to be reduced to a 1,000 ppmv concentration level. From Tables 3-1, 4-1, 4-2, and References 1 and 2.

4.3 PREVENTIVE PROGRAMS

An alternative approach to controlling fugitive VOC emissions from gas plant operations is to replace components with leakless equipment. This approach is referred to as a preventive program. This section will discuss the kinds of equipment that could be applied in such a program and the advantages and disadvantages of this equipment.

4.3.1 Pressure Relief Valves

As discussed in Chapter 3, pressure relief valves can be sources of fugitive VOC emissions because of leakage through the valve seat. This type of leakage can be prevented by installing a rupture disk upstream of the valve, by connecting the discharge port of the valve to a closed-vent system, or by use of soft seat technology such as elastomer "O-rings." A rupture disk can be used upstream of a pressure relief valve so that under normal conditions it seals the system tightly but will break when its set pressure is exceeded, at which time the pressure relief valve will relieve the pressure. Figure 4-1 is a diagram of a rupture disk and pressure relief valve installation. The installation is arranged to prevent disk fragments from lodging in the valve and preventing the valve from being reseated if the disk ruptures. It is important that no pressure be allowed to build in the pocket between the disk and the pressure relief valve; otherwise, the disk will not function properly. A pressure gauge and bleed valve can be used to prevent pressure buildup. With the use of a pressure gauge, it can be determined whether the disk is properly sealing the system against leaks.

It may be necessary to install a 2-port valve and parallel relief valve when using a rupture disk upstream of a relief valve. Such a system may be required to isolate the relief valve/rupture disk system for repair in case of an overpressure discharge. The parallel system would provide a backup relief valve during repair. However, a block valve upstream of the rupture disk/relief valve system will accomplish the same purpose where safety codes allow the use of a block valve for this purpose.

An alternative method for controlling pressure relief valve emissions due to improper reseating is the use of a soft elastomer seat in the valve. An elastomer "O-ring" can be installed so that the

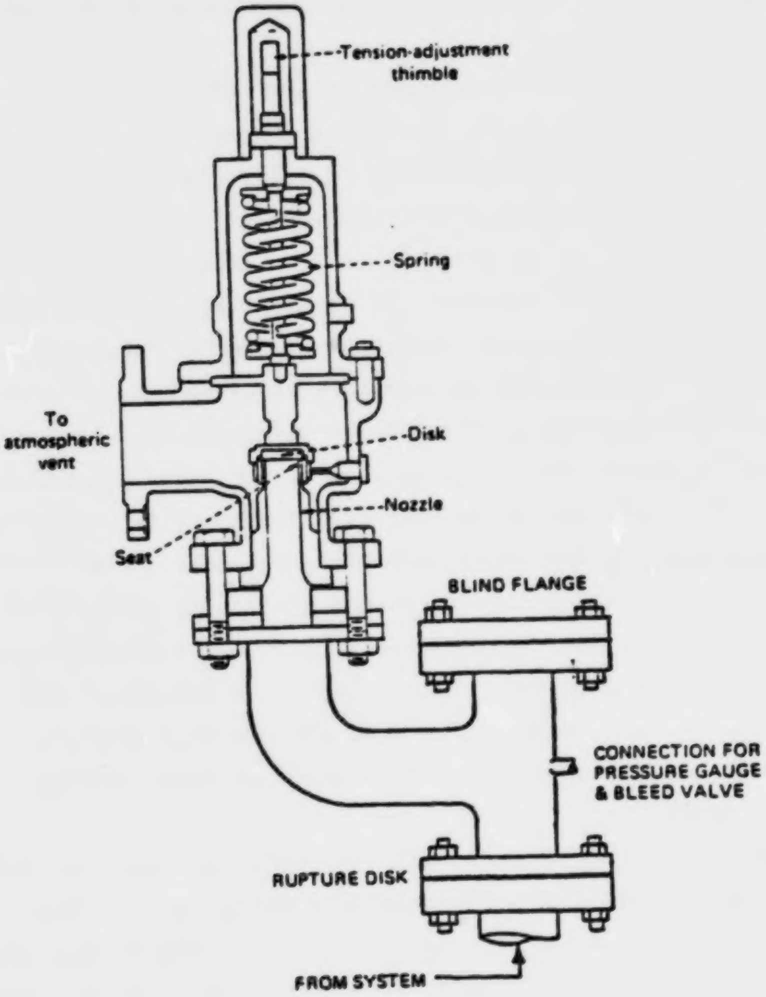

Tension-adjustment thimble
Spring
To atmospheric vent
Disk
Nozzle
Seat
BLIND FLANGE
CONNECTION FOR PRESSURE GAUGE & BLEED VALVE
RUPTURE DISK
FROM SYSTEM

Figure 4-1. Rupture disk installation upstream of a relief valve.[3]

valve always forms a tight seal after an overpressure discharge. However, this approach will not prevent leakage due to "simmering," a condition due to the system pressure being too close to the set pressure of the valve.

4.3.2 Compressor Seals

As discussed in Chapter 3, there are three types of compressors used in natural gas plants: centrifugal, rotary, and reciprocating. Centrifugal and rotary compressors are driven by rotating shafts while reciprocating compressors are driven by shafts having a linear reciprocating motion. In either case, fugitive emissions occur at the junction of the moving shafts and the stationary casing, but the kinds of controls that can be effectively applied depend on the type of shaft motion involved.

4.3.2.1 Centrifugal and Rotary Compressors. Centrifugal and rotary compressors are both driven by rotating shafts. Emissions from these types of compressors can be controlled by the use of mechanical seals with barrier fluid (liquid or gas) systems or by the use of liquid film seals. In both of these types of seals, a fluid is injected into the seal at a pressure higher than the internal pressure of the compressor. In this way, leakage of the process gas to atmosphere is prevented except when there is a seal failure. As in the case of pumps, seal fluid degassing vents must be controlled with a closed vent system to prevent process gas from escaping from the vent.

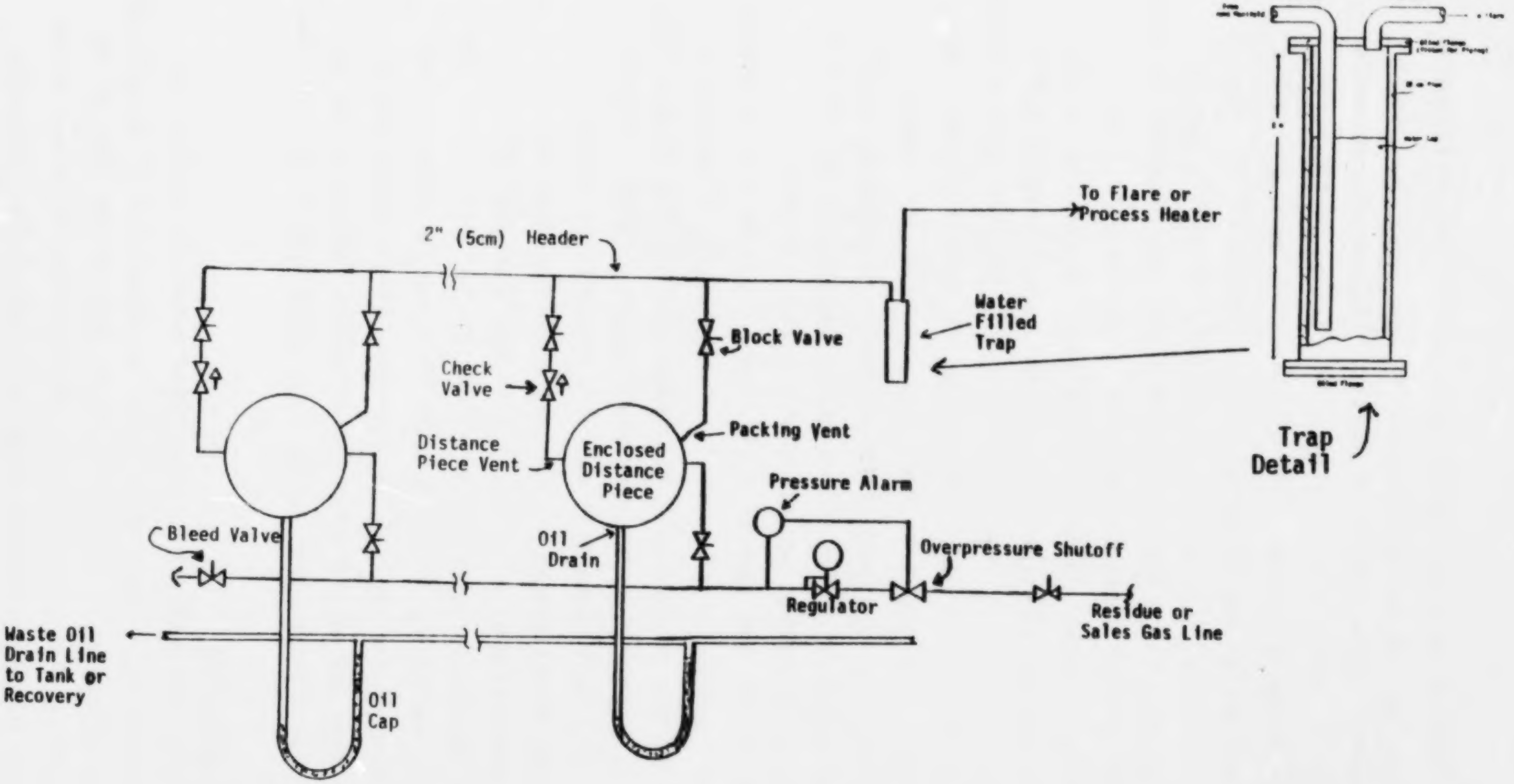
4.3.2.2 Reciprocating Compressors. This type of compressor usually involves a piston, cylinder, and drive-shaft arrangement. Since the shaft motion is linear, a packing gland arrangement is normally employed to prevent leakage around the moving shaft. This type of seal can be improved by inserting one or more spacer rings into the packing and connecting the void area or areas thus produced to a collection system through vents in the housing. This is referred to as a "scavenger" system. As with other fugitive emission collection systems, these vents must be controlled to prevent fugitive emissions from entering the atmosphere. However, venting the seal does not eliminate emissions from reciprocating compressors entirely, because emissions can still occur into the distance piece area. These leaks can be controlled by enclosing the distance piece area and installing suitable piping to vent the emissions either to a flare, a plant process heater, or back into a low pressure point in the process. For the latter two cases, an auxilliary compressor may be required to compress the vent stream to a usable pressure. Purging the distance piece with natural gas could be performed to keep the enclosure above the upper explosive limit and to ensure a nonexplosive atmosphere (Figure 4-2).

As shown in Figure 4-2, the distance piece enclosure could be maintained slightly above atmospheric pressure by purging the enclosure with residue or sales gas through a regulator. To ensure safety, either double distance pieces[13] or more sophisticated piston rod seals[12] should be employed. Additionally, a high pressure sensor in the purge gas line should be used to shut off the gas supply in the event of regulator failure. In order to provide for draining of seal oil leaks, the atmospheric pressure oil drain line should be connected through a "U" tube trap as shown to prevent loss of the purge gas while allowing uninterrupted oil flow. A second water filled trap in the outlet serves to maintain the pressure in the enclosure, while allowing free flow of emissions (or seal failure gases) to the control device by displacement of the water into the knockout drum when the pressure in the system exceeds the water column height set pressure.

Obtaining a good seal at the distance piece door and at the point where emissions are vented from the distance piece or seal area is necessary for maintaining a sufficient pressure (e.g., 2 to 5 psig). Block valves should also be installed in order to close vent lines during compressor shutdown periods. This will prevent hydrocarbon vapors from entering the work place and air from entering the vent system during compressor maintenance.[14] There may be instances where retrofitting of such a vent control system to a compressor distance piece may be infeasible for safety reasons.[15] Therefore, the application of this preventive program as a retrofit will have to be evaluated on a case-by-case basis.

4.3.3 Pump Seals

Pumps can be potential fugitive VOC emission sources because of leakage through the drive-shaft sealing mechanism. This kind of



To Flare or Process Heater
2" (5cm) Header
Water Filled Trap
Block Valve
Check Valve
Distance Piece Vent
Packing Vent
Enclosed Distance Piece
Trap Detail
Pressure Alarm
Bleed Valve
Oil Drain
Overpressure Shutoff
Regulator
Residue or Sales Gas Line
Waste Oil Drain Line to Tank or Recovery
Oil Cap

Figure 4-2. COMPRESSOR DISTANCE PIECE PURGE SYSTEM

leakage can be reduced to a negligible level through the installation of improved shaft sealing mechanisms, such as dual mechanical seals.

Dual mechanical seals consist of two mechnical sealing elements usually arranged in either a back-to-back or a tandem configuration. In both configurations a barrier fluid circulates between the seals. The barrier fluid system may be circulating system, or it may rely on convection to circulate fluid within the system. While the barrier fluid's main function is to keep the pumped fluid away from the environment, it can serve other functions as well. A barrier fluid can provide temperature control in the stuffing box. It can also protect the pump seals from the atmosphere, as in the case of pumping easily oxidizable materials that form abrasive oxides or polymers upon exposure to air. A wide variety of fluids can be used as barrier fluids. Some of the more common ones that have been used are water (or steam), glycols, methanol, oil, and heat transfer fluid. In cases in which product contamination cannot be tolerated, it may also be possible to use clean product, a product additive, or a product diluent.

Emissions of VOC from barrier fluid degassing vents can be controlled by a closed vent system, which consists of piping and, if necessary, flow inducing devices to transport the degassing emissions to a control device, such as a process heater, or vapor recovery system. Control effectiveness of a dual mechanical seal and closed vent system is dependent on the effectiveness of the control device used and the frequency of seal failure. Failure of both the inner and outer seals can result in relatively large VOC emissions at the seal area of the pump. Pressure monitoring of the barrier fluid may be used in order to detect failure of the seals.[3] In addition, visual inspection of the seal area also can be effective for detecting failure of the outer seals. Upon seal failure, the leaking pump would have to be shut down for repair.

4.3.4 Open-Ended Lines

Caps, plugs, and double block and bleed valve are devices for closing off open-ended lines. When installed downstream of an open-ended line, they are effective in preventing leaks through the seat of the valve from reaching atmosphere. In the double block and bleed system, it is important that the upstream valve be closed first. Otherwise, product will remain in the line between the valves, and expansion of this product can cause leakage through the valve stem seals.

The control efficiency will depend on such factors as frequency of valve use, valve seat leakage, and material that may be trapped in the cap or plug. Annual VOC emissions from a leaking open-ended valve are approximately 100 kg.[16] Assuming that open-ended lines are used an average of 10 times per year, that 0.1 kg of trapped organic material is released when the valve is used, and that all of the trapped organics released are emitted to atmosphere, the annual emissions from closed off open-ended lines would be 1 kg. This would be a 99 percent reduction in emissions. Due to the conservative nature of these assumptions, a 100 percent control efficiency has been used to estimate the emission reductions of closing off open-ended lines.

4.3.5 Closed-Purge Sampling

VOC emissions from purging sampling lines can be controlled by a closed-purge sampling system, which is designed so that the purged VOC is returned to the system or sent to a closed disposal system so that the handling losses are minimized. Figure 4-2 gives two examples of closed-purge sampling systems where the purged VOC is flushed from a point of higher pressure to one of lower pressure in the system and where sample-line dead space is minimized. Other sampling systems are available that utilize partially evacuated sampling containers and require no line pressure drop.[17]

Reduction of emissions for closed-purge sampling is dependent on many highly variable factors, such as frequency of sampling and amount of purge required. For emission calculations, it has been assumed that closed-purge sampling systems will provide 100 percent control efficiency for the sample purge.

4.3.6 Gas-Operated Control Valves

VOC emissions from pneumatic control valves result when field gas or flash gas is used as the operating medium. These emissions can be eliminated by the use of compressed air. This will require installation of an air compression system and connection of the appropriate pressure supply lines.

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5. MODIFICATION AND RECONSTRUCTION

In accordance with the provisions of Title 40 of the Code of Federal Regulation (CFR), Sections 60.14 and 60.15, an existing facility can become an affected facility and, consequently, subject to the standards of performance if it is modified or reconstructed. An "existing facility," defined in 40 CFR 60.2, is a facility of the type for which a standard of performance is promulgated and the construction or modification of which was commenced prior to the proposal date of the applicable standards. The following discussion examines the applicability of modification/reconstruction provisions to natural gas/gasoline processing plants that involve fugitive VOC emissions.

5.1 GENERAL DISCUSSION OF MODIFICATION AND RECONSTRUCTION PROVISIONS

5.1.1 Modification

Modification is defined in Section 60.14 as any physical or operational change to an existing facility that results in an increase in the emission rate of the pollutant(s) to which the standard applies. Paragraph (e) of Section 60.14 lists exceptions to this definition which are not considered modifications, irrespective of any changes in the emission rate. These changes include:

1. Routine maintenance, repair, and replacement;
2. An increase in the production rate not requiring a capital expenditure as defined in Section 60.2(bb);
3. An increase in the hours of operation;
4. Use of an alternative fuel or raw material if, prior to the standard, the existing facility was designed to accommodate that alternative fuel or raw material;
5. The addition or use of any system or device whose primary function is the reduction of air pollutants, except when an emission

control system is removed or replaced by a system considered to be less environmentally beneficial.

As stated in paragraph (b), emission factors, material balances, continuous monitoring systems, and manual emission tests are to be used to determine emission rates expressed as kg/day of pollutant. Paragraph (c) affirms that the addition of an affected facility to a stationary source through any mechanism -- new construction, modification, or reconstruction -- does not make any other facility within the stationary source subject to standards of performance. Paragraph (f) provides for superseding any conflicting provisions. And, (g) stipulates that compliance be achieved within 180 days of the completion of any modification.

5.1.2 Reconstruction

Under the provisions of Section 60.15, an existing facility becomes an affected facility upon reconstruction, irrespective of any change in emission rate. A source is identified for consideration as a reconstructed source when: (1) the fixed capital costs of the new components exceed 50 percent of the fixed capital costs that would be required to construct a comparable entirely new facility, and (2) it is technologically and economically feasible to meet the applicable standards set forth in this part. The final judgment on whether a replacement constitutes reconstruction will be made by the Administrator's determination of reconstruction will be based on:

> (1) The fixed capital cost that would be required to construct a comparable new facility; (2) the estimated life of the facility after the replacements compared to the life of a comparable entirely new facility; (3) the extent to which the components being replaced cause or contribute to the emissions from the facility; and (4) any economic or technical limitations in compliance with applicable standards of performance which are inherent in the proposed replacements.

The purpose of the reconstruction provision is to ensure that an owner or operator does not perpetuate an existing facility by replacing all but minor components, support structures, frames, housing, etc., rather than totally replacing it in order to avoid being subject to applicable performance standards. In accordance with Section 60.5, EPA will, upon request, determine if an action taken constitutes construction (including reconstruction).

5.2 APPLICABILITY OF MODIFICATION AND RECONSTRUCTION PROVISIONS TO NATURAL GAS/GASOLINE PROCESSING PLANTS

As a result of cost and energy considerations, as well as changes in product demand and feedstock supply, there are expected to be a number of modernization projects at existing gas plants in the near future. Some of these projects could result in existing gas plants becoming subject to the provisions of Sections 60.14 and 60.15.

For example, a company may decide to add process trains at an existing facility in order to increase the plant capacity or efficiency. The additional process equipment would include additional sources of potential fugitive emissions, such as valves or compressors. Routine changes are also made to gas plants, such as those made to increase ease of maintenance, to increase productivity, to improve plant safety, or correct minor design flaws. These types of changes may also result in an increase of fugitive emissions. However, measures could be taken to reduce fugitive emissions from other sources to compensate for the increase. The capital expenditure for any of the above additions, replacements, or changes may exceed the level of capital expenditure as defined in Section 60.2(bb). Some changes may involve only the replacement of a potential fugitive emission source such as a valve. If the source is replaced with an equivalent source the level of fugitive emissions would be expected to remain unchanged.

It may be advantageous for certain plants to convert to an entirely different processing method. Most new gas plants use the cryogenic processing method because it is less costly to operate and because it is more efficient. For the same reasons, owners of existing plants may decide to convert to the cryogenic method. Depending on the process method that is presently being used, this may involve a substantial amount of new equipment. It is possible that the cost of the conversion would exceed 50 percent of the cost of a new plant.

6.0 MODEL PLANTS AND REGULATORY ALTERNATIVES

6.1 INTRODUCTION

This chapter presents model plants and regulatory alternatives for reducing fugitive VOC emissions from natural gas/gasoline processing plants. The model plants were selected to represent the range of processing complexity in the industry. They provide a basis for determining environmental and cost impacts of the regulatory alternatives. The regulatory alternatives consist of various combinations of the available control techniques and provide incremental levels of emission control.

6.2 MODEL PLANTS

There are a number of different process methods used at gas plants: absorption, refrigerated absorption, refrigeration, compression, adsorption, cryogenic - Joule-Thomson, and cryogenic-expander.[1] Process conditions are expected to vary widely between plants using these different methods. However, available data show that fugitive emissions are proportional to the number of potential sources, and are not related to capacity, throughput, age, temperature, or pressure.[2] Therefore, model plants defined for this analysis represent different levels of process complexity (number of fugitive emission sources), rather than different process methods.

In order to estimate emissions, control costs, and environmental impacts on a plant specific basis, three model plants were developed. With the exception of sampling connections, the number of components for each model plant is derived from actual component inventories performed at four gas plants. Two of the plants were inventoried during EPA testing,[3] and two were inventoried during testing by Rockwell International under contract to the American Petroleum Institute.[4] The number of sampling connections is based on one liquid sampling connection at each pump and one gas sampling connection at each compressor.

Complexity of gas plants can be indexed by means of calculating ratios of component populations to a more easily counted population. For gas plants, the number of vessels appears to be best suited to this need. Equipment included and excluded in vessel inventories are listed in Table 6-1. The vessel inventories for the industry-tested gas plants are taken from the site diagrams and descriptions provided in the API/Rockwell report,[6] and the vessel inventories from the EPA-tested plants were performed during the testing. These vessel inventories and the component inventories are shown in Table 6-2. Table 6-3 shows the ratios of numbers of components to numbers of vessels at the four gas plants. The mean and standard deviation of the four ratios are also shown in Table 6-3.

Three model plants have been developed using the average ratios of components to vessels. The number of vessels in the model gas plants are 10, 30, and 100. This range in number of vessels is based on the vessel inventories shown in Table 6-2. The low end of the range, 10 vessels, is approximately equivalent to the number of vessels that are accounted for in one of the three process trains at the EPA-tested plant A. It is assumed that there are existing gas plants with a similar configuration to the EPA-tested plant A, that have only one process train. The high end of the range, 100 vessels, is slightly larger than the number of vessels at the industry-tested plant C. Since this was the largest of the plants tested, it appears reasonable to use this as a guide in calculating the number of components at the largest model plant. The middle-sized model plant has 30 vessels. This is approximately the same number of vessels as at three of the four plants tested and may be representative of a common gas plant size. The three model plants and their respective number of components are shown in Table 6-4.

6.3 REGULATORY ALTERNATIVES

This section presents four regulatory alternatives for controlling fugitive VOC emissions from natural gas/gasoline processing plants. The alternatives define feasible programs for achieving varying levels of

Table 6-1. EXAMPLE TYPES OF EQUIPMENT INCLUDED AND EXCLUDED IN VESSEL INVENTORIES FOR MODEL PLANT DEVELOPMENT

Included	Excluded
1. Absorption/Desorption Units a. Absorbers b. Scrubbers c. Dehydrators d. Stabilizer e. Stripper 2. Adsorption Units 3. Distillation/Fractionation Units a. Demethanizer b. Deethanizer c. Depropanizer d. Splitter e. Flash Drum/Tank f. Stills 4. Heating/Cooling Units a. Heaters b. Chillers c. Heat Exchangers d. Reboilers e. Condensers f. Coolers 5. Drums/Tanks a. Separator b. Surge c. Gas d. Oil e. Accumulator f. Knockout	1. Compressors, Pumps 2. Piping Systems a. Manifold/header systems b. Valves, flanges, connections, etc. c. Meters, gauges, control equipment 3. Glycol, lube oil, water storage 4. Any equipment associated with sweetening

Table 6-2. NUMBER OF COMPONENTS IN HYDROCARBON SERVICE AND NUMBER OF VESSELS AT FOUR GAS PLANTS

	EPA tested plants[a]		Industry tested plants[b]	
	A	B	C	D
Vessels	31	30	90	25
Valves	508[c]	541	3,330	762
Relief valves	16[c]	11	20	7
Open-ended lines	62[c]	64	669	173
Compressor seals	0	8	35	0
Pump seals	1[c]	12	32	3
Flanges and connections	1,530[c]	1,440	15,370	3,030

[a] Reference 3.

[b] Reference 4.

[c] Only two of the three adsorption units at the plant were tested and inventoried. Estimated total number of components is therefore based on the sum of the number of components counted in the larger unit plus twice the number of components counted in the smaller unit.

Table 6-3. RATIOS OF NUMBERS OF COMPONENTS TO NUMBERS OF VESSELS[a]

	EPA tested plants		Industry tested plants		Average ratio	Standard deviation of ratio
	A	B	C	D		
Valves	16.4	18.0	37.0	30.5	25.5	9.9
Relief valves	0.5	0.4	0.2	0.3	0.4	0.1
Open-ended lines	2.0	2.1	7.4	6.9	4.6	3.0
Compressor seals	0.0	0.3	0.4	0.0	0.2	0.2
Pump seals	0.0	0.4	0.4	0.1	0.2	0.2
Flanges and connections	49.4	48.0	170.8	121.2	97.4	59.7

[a] Based on data presented in Table 6-2.

Table 6-4. FUGITIVE VOC EMISSION SOURCES FOR THREE MODEL GAS PROCESSING PLANTS

	Number of components		
Component type	Model plant A (10 vessels)	Model plant B (30 vessels)	Model plant C (100 vessels)
Valves[a]	250	750	2,500
Relief valves[a]	4	12	40
Open-ended lines[a]	50	150	500
Compressor seals[a]	2	6	20
Pump seals[a]	2	6	20
Sampling connections[b]			
Liquid	2	6	20
Gas	2	6	20
Flanges and connections[a]	1,000	3,000	10,000

[a] Number of components based on average ratios presented in Table 6-3.

[b] Based on one liquid connection at each pump and one gas connection at each compressor.

emission reduction. The first alternative represents a baseline level of fugitive emissions in which case the impact analysis is based on no additional controls. The remaining regulatory alternatives require increasingly restrictive controls comprised of the techniques discussed in Chapter 4. Table 6-5 summarizes the requirements of the regulatory alternatives.

6.3.1 Regulatory Alternative I

Regulatory Alternative I reflects normal existing gas plant operations with no additional regulatory requirements. This baseline regulatory alternative provides the basis for incremental comparison of the impacts of the other regulatory alternatives.

6.3.2 Regulatory Alternative II

Regulatory Alternative II provides a higher level of emission control than the baseline alternative through leak detection and repair methods as well as equipment specifications.

This regulatory alternative requires quarterly instrument monitoring of valves, relief valves, compressor seals, and pump seals for leaks. Leaks that are found to be in excess of a prescribed hydrocarbon concentration (as indicated by a hydrocarbon detection instrument) would be repaired within a prescribed time period. Pump seals would additionally receive weekly visual inspections for leaks. Leaks found to be in excess of the prescribed concentration would be repaired within the prescribed time period.

The regulatory alternative also requires that caps (including plugs, flanges, or second valves) be installed on open-ended lines.

6.3.3 Regulatory Alternative III

Regulatory Alternative III achieves a greater emission reduction than Alternative II by requiring monthly instrument monitoring of valves, relief valves, and pump seals. If a particular valve is found not to be leaking for 3 successive months, then 2 months may be skipped before the next time it is monitored with an instrument. A compressor vent control system would be installed to control compressor seal emissions. Sampling connections would be equipped with a closed purge sampling system. Other requirements (caps on open-ended lines, weekly inspection of pumps) remain the same as Alternative II.

Table 6-5. FUGITIVE VOC REGULATORY ALTERNATIVE CONTROL SPECIFICATIONS

	Regulatory Alternative						
	I	II		III		IV	
Component type		Monitoring interval	Equipment specification	Monitoring interval	Equipment specification	Monitoring interval	Equipment specification
Valves	baseline control (no NSPS)	quarterly		monthly/ quarterly		monthly	
Relief valves		quarterly		monthly			rupture disc
Open-ended lines			cap		cap		cap
Sampling connections			none		closed purge sampling		closed purge sampling
Compressor seals		quarterly[a]			compressor vent control		compressor vent control
Pump seals		quarterly, weekly visual[b]		monthly, weekly visual[b]			dual seals

[a] Quarterly monitoring and repair is not an effective control technique for all compressors. In some instances, reduction in emissions from compressors through seal repair may necessitate a process unit turnaround because compressors generally are not spared. In addition, it may not be possible to repair a compressor seal to below a prescribed leak definition because the seals can normally operate with concentrations above the action level. In these instances a compressor vent control system should be substituted for monitoring.

[b] Instrument monitoring of pumps would be supplemented with weekly visual inspections for liquid leakage. If liquid is noted to be leaking from the pump seal, the seal would be repaired.

6.3.4 Regulatory Alternative IV

Regulatory Alternative IV increases emission control by requiring monthly instrument monitoring of valves. Relief valves should be equipped with a rupture disc, and pumps are required to have dual mechanical seals. Other requirements are the same as Alternative III.

6.4 REFERENCES

1. Cantrell, A. Worldwide Gas Processing. Oil and Gas Journal, July 14, 1980. p. 88. Docket Reference Number II-I-23.*

2. Assessment of Atmospheric Emissions from Petroleum Refining, Volume 3, Appendix B. EPA 600/2-80-075c, April 1980. Pages 266 and 280. Docket Reference Number II-A-8.*

3. Hustvedt, K.C., memo to James F. Durham, Chief, Petroleum Section, OAQPS, U.S. EPA. Preliminary Test Data Summaries of EPA testing at Houston Oil and Minerals Smith Point gas plant and Amoco Production Hastings gas plant. March 19, 1981. Docket Reference Number II-B-19*.

4. Eaton, W.S., Rockwell International, letter to D. Markwordt, OAQPS, U.S. EPA. Component Inventory Data from Two API-Tested Gas Plants. September 11, 1980. Docket Reference Number II-D-5.*

5. VOC Fugitive Emissions in Petroleum Refining Industry — Background Information for Proposed Standards. U.S. EPA, OAQPS. April 1981. Docket Reference Number II-A-10.*

6. Eaton, W.S., et al. Fugitive Hydrocarbon Emissions from Petroleum Production Operations. API Publication No. 4322. March 1980. Docket Reference Number II-I-20, Vol. 1.1* and Docket Reference Number II-I-21, Vol. 1.2*

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*References can be located in Docket Number A-80-20-B at the U.S. Environmental Protection Agency Library, Waterside Mall, Washington, D.C.

7.0 ENVIRONMENTAL IMPACTS

7.1 INTRODUCTION

This chapter discusses the environmental impacts from implementing the regulatory alternatives presented in Chapter 6. The primary emphasis is a quantitative assessment of the fugitive emissions that would result from each of the alternatives. The impacts on water quality, solid waste, energy and other environmental concerns are also addressed.

7.2 EMISSIONS IMPACT

7.2.1 Emission Source Characterization

As discussed in Chapter 6, the model plants consist of several types of components (e.g., valves, pumps) that comprise the major fugitive emission sources within natural gas/gasoline processing plants. The emission factors presented in Table 3-1 are characteristic of existing gas plant components. These emissions are referred to as "baseline" and represent emissions under Regulatory Alternative I. The control technology discussed in Chapter 4 is applied in progressive increments in Alternatives II, III, and IV in reducing emissions below baseline levels.

7.2.2 Development of Emission Levels

In order to estimate the impacts of the regulatory alternatives on fugitive VOC emission levels, emission factors for the model plants were determined for each regulatory alternative. Controlled emission factors were developed for those component types that would be controlled by the implementation of a leak detection and repair program and are given in Table 7-1. Controlled emission factors for pressure relief valves and compressor seals were derived based upon the ABCD model correction factors and the leak detection and repair (LDAR) model as discussed in Chapter 4.[5] Controlled emission factors for valves and pump seals were derived directly from the LDAR model as described in Chapter 4 and Appendix E.

Table 7-1. CONTROLLED EMISSION FACTORS FOR VARIOUS INSPECTION INTERVALS

Source Type	Inspection Interval	Baseline Emission Factor[a] (kg/day)	Control Efficiency	Controlled Emission Factor[b] (kg/day)
Valves	Quarterly	0.18 (0.48)	0.77 (0.77)[c]	0.041 (0.11)
	Monthly/ Quarterly		0.78 (0.78)	0.041 (0.11)
	Monthly		0.84 (0.84)	0.029 (0.077)
Relief valves	Quarterly	0.33 (4.5)	0.63 (0.69)[d]	0.12 (1.4)
	Monthly		0.70 (0.76)	0.10 (1.1)
Compressor seals	Quarterly	1.0 (4.9)	0.82 (0.78)[d]	0.18 (1.1)
Pump seals	Quarterly	1.2 (1.5)	0.58 (0.58)[c]	0.50 (0.63)
	Monthly		0.65 (0.65)	0.42 (0.53)

xx = VOC emission values
(xx) = THC emission values

[a] From Table 3-1.

[b] Controlled emission factor = baseline emission factor x (1-control efficiency).

[c] From Table E-1.

[d] References 4, 5.

Where the regulatory alternatives require an equipment specification, it is assumed that there are no subsequent emissions from the controlled source. Table 7-2 presents the total fugitive VOC emissions from Model Plants A, B, and C under each regulatory alternative by component type and the component percent of the total emissions. Table 7-3 compares the control effectiveness of Regulatory Alternatives II through IV over Alternative I (baseline emissions) and the incremental cost effectiveness between each regulatory alternative and the previous alternative.

7.2.3 Future Impact on Fugitive VOC Emissions

Future impacts of the regulatory alternatives were estimated for the 5-year period, 1983 to 1987 as shown in Table 7-4. The number of affected model plants (detailed in Section 9.1.2.2) projected for each year was multiplied by the estimated total fugitive emissions per model plant for each of the alternatives (from Table 7-3).

Over the 5-year period, the total fugitive VOC emissions for new plants under baseline control (Regulatory Alternative I) are projected at 52 gigagrams. These baseline emissions may reach an additional 19 gigagrams from existing plants through modification/reconstruction. Implementation of Regulatory Alternatives II through IV would reduce the total new plant emissions to 16, 14, and 11 gigagrams, respectively. Modification/reconstruction may add up to 5.6, 5.0, and 4.1 gigagrams, respectively, to the new plant projections.

7.3 WATER QUALITY IMPACT

Although fugitive emissions from gas plant equipment primarily impact air quality, they also adversely impact water quality. In particular, leaking components handling liquid hydrocarbon streams increase the waste load entering wastewater treatment systems. Leaks from equipment contribute to the waste load by entering drains via run-off. Implementation of Regulatory Alternatives II through IV would reduce the waste load on wastewater treatment systems by preventing leakage from process equipment from entering the wastewater system.

7.4 SOLID WASTE IMPACT

Solid wastes that are generated by the natural gas/gasoline processing industry and that are associated with the regulatory alternatives include replaced mechanical seals, seal packing, rupture disks, and valves.

Table 7-2. EMISSIONS FOR REGULATORY ALTERNATIVES (MODEL PLANT A)

	Regulatory Alternative*							
	I		II		III		IV	
Component type	Baseline emissions, kg/day	Percent total emissions	Controlled emissions, kg/day	Percent total emissions	Controlled emissions, kg/day	Percent total emissions	Controlled emissions, kg/day	Percent total emissions
Valves	45 (120)	57 (59)	10 (28)	43 (44)	10 (28)	45 (47)	7.3 (20)	40 (43)
Relief valves	1.3 (18)	2 (9)	0.48 (5.6)	2 (9)	0.40 (4.4)	2 (7)	0.0 (0.0)	0 (0)
Open-ended lines	17 (27)	22 (13)	0.0 (0.0)	0 (0)	0.0 (0.0)	0 (0)	0.0 (0.0)	0 (0)
Compressor seals	2.0 (9.8)	3 (5)	0.36 (2.2)	2 (3)	0.0 (0.0)	0 (0)	0.0 (0.0)	0 (0)
Pump seals	2.4 (3.0)	3 (1)	1.0 (1.3)	4 (2)	0.84 (1.1)	4 (2)	0.0 (0.0)	0 (0)
Sampling[a] connections	G .03 (.64) L .17 (.17)	<1 (<1) <1 (<1)	0.3 (.64) .17 (.17)	<1 (<1) <1 (<1)	0.0 (0.0) 0.0 (0.0)	0 (0) 0 (0)	0.0 (0.0) 0.0 (0.0)	0 (0) 0 (0)
Flanges and connections	11 (26)	14 (13)	11 (26)	48 (41)	11 (26)	49 (44)	11 (26)	60 (57)
Total	79 (205)		23 (64)		22 (60)		18 (46)	

* From Chapter 6

xx = VOC emission values

(xx) = THC emission values

[a] G = Gas Service
L = Liquid Service

Table 7-2. EMISSIONS FOR REGULATORY ALTERNATIVES (MODEL PLANT B) Continued

	Regulatory Alternative*							
	I		II		III		IV	
Component type	Baseline emissions, kg/day	Percent total emissions	Controlled emissions, kg/day	Percent total emissions	Controlled emissions, kg/day	Percent total emissions	Controlled emissions, kg/day	Percent total emissions
Valves	140 (360)	57 (59)	31 (83)	43 (44)	31 (83)	46 (47)	22 (59)	40 (43)
Relief valves	4.0 (54)	2 (9)	1.4 (17)	2 (9)	1.2 (13)	2 (7)	0.0 (0.0)	0 (0)
Open-ended lines	51 (80)	22 (13)	0.0 (0.0)	0 (0)	0.0 (0.0)	0 (0)	0.0 (0.0)	0 (0)
Compressor seals	6.0 (29)	3 (5)	1.1 (6.6)	2 (3)	0.0 (0.0)	0 (0)	0.0 (0.0)	0 (0)
Pump seals	7.2 (9.0)	3 (1)	3.0 (3.8)	4 (2)	2.5 (3.2)	4 (2)	0.0 (0.0)	0 (0)
Sampling[a] connections	G. .09 (1.9) L. .51 .51	<1 (<1) <1 (<1)	0.9 (1.9) .51 .51	<1 (<1) <1 (<1)	0.0 (0.0) 0.0 (0.0)	0 (0) 0 (0)	0.0 (0.0) 0.0 (0.0)	0 (0) 0 (0)
Flanges and connections	33 (78)	14 (13)	33 (78)	48 (41)	33 (78)	49 (44)	33 (78)	60 (57)
Total	242 (612)		71 (191)		68 (177)		55 (140)	

* From Chapter 6

xx = VOC emission values

(xx) = THC emission values

[a] G = Gas Service
L = Liquid Service

Table 7-2. EMISSIONS FOR REGULATORY ALTERNATIVES (MODEL PLANT C) Concluded

	Regulatory Alternative							
	I		II		III		IV	
Component type	Baseline emissions, kg/day	Percent total emissions	Controlled emissions, kg/day	Percent total emissions	Controlled emissions, kg/day	Percent total emissions	Controlled emissions, kg/day	Percent total emissions
Valves	450 (1,200)	57 (59)	100 (280)	39 (43)	100 (280)	45 (47)	73 (200)	40 (43)
Relief valves	13 (180)	2 (9)	4.8 (56)	2 (9)	4.0 (44)	2 (7)	0.0 (0.0)	0 (0)
Open-ended lines	170 (265)	22 (13)	0.0 (0.0)	0 (0)	0.0 (0.0)	0 (0)	0.0 (0.0)	0 (0)
Compressor seals	20 (98)	3 (5)	0.36 (22)	1 (3)	0.0 (0.0)	0 (0)	0.0 (0.0)	0 (0)
Pump seals	24 (30)	3 (1)	10 (13)	4 (2)	8.4 (11)	4 (2)	0.0 (0.0)	0 (0)
Sampling[a] connections	G. 0.3 (6.4) L. 1.7 (1.7)	<1 (<1) <1 (<1)	0.3 (6.4) 1.7 1.7	<1 (<1) <1 (<1)	0.0 (0.0) 0.0 (0.0)	0 (0) 0 (0)	0.0 (0.0) 0.0 (0.0)	0 (0) 0 (0)
Flanges and connections	110 (260)	14 (13)	110 (260)	43 (40)	110 (260)	49 (44)	110 (260)	60 (57)
Total	789 (2,041)		227 (643)		220 (600)		180 (460)	

xx = VOC emission values.

(xx) = Total hydrocarbon emission values.

[a] G = Gas Service
L = Liquid Service

Table 7-3. TOTAL AND INCREMENTAL EMISSION REDUCTIONS OF THE REGULATORY ALTERNATIVES ON A MODEL PLANT BASIS

Regulatory alternative	Model plant emissions,[a] Mg/yr			Percent emission reduction	
	A	B	C	Total[b]	Incremental[c]
I	29 (75)	88 (223)	288 (745)	--	--
II	8.4 (23)	26 (70)	83 (235)	70 (68)	70 (68)
III	8.0 (22)	25 (65)	80 (220)	73 (71)	3 (3)
IV	6.6 (17)	20 (51)	66 (170)	78 (77)	5 (6)

xx = VOC emission values.

(xx) = Total hydrocarbon emission values.

[a] From Table 7-2. Assume 365 days per year operation.

[b] Emissions reduction from Regulatory Alternative I.

[c] Emissions reduction from previous Regulatory Alternative.

Table 7-4. PROJECTED FUGITIVE EMISSIONS FROM AFFECTED MODEL PLANTS AND REGULATORY ALTERNATIVES FOR 1983-1987

		Cumulative number of affected model plants[a]			Total fugitive emissions projected under regulatory alternative[b] (1000 Mg/yr)			
	Year	A	B	C	I	II	III	IV
New plants	1983	0	40	0	3.5 (8.9)	1.0 (2.8)	1.0 (2.6)	0.80 (2.0)
	1984	0	80	0	7.0 (18)	2.2 (5.6)	2.0 (5.2)	1.6 (4.1)
	1985	0	120	0	11 (27)	3.1 (8.4)	3.0 (7.8)	2.4 (6.1)
	1986	0	150	0	13 (33)	3.9 (11)	3.8 (9.8)	3.0 (7.7)
	1987	0	180	0	16 (40)	4.7 (13)	4.5 (12)	3.6 (9.2)
	5th - year emission reduction from baseline				– (–)	11.3 (27)	11.5 (28)	12.4 (30.8)
Modified/ reconstructed plants	1983	2	3	3	1.2 (3.1)	0.34 (0.96)	0.33 (0.90)	0.27 (0.70)
	1984	4	6	6	2.5 (6.1)	0.69 (1.9)	0.67 (1.8)	0.54 (1.4)
	1985	6	9	9	3.7 (9.2)	1.0 (2.9)	1.0 (2.7)	0.81 (2.1)
	1986	8	12	12	4.9 (12)	1.4 (3.8)	1.3 (3.6)	1.1 (2.8)
	1987	10	15	15	6.2 (15)	1.7 (4.8)	1.7 (4.5)	1.4 (3.5)
	5th - year emission reduction from baseline				– (–)	4.5 (10.2)	4.5 (10.5)	4.8 (11.5)

xx = VOC emission values.

(xx) = Total hydrocarbon emission values.

[a] The number of affected model plants projected through 1987 distinguish between new plant construction and modification/reconstruction. Plants in existence prior to 1983 are otherwise excluded. A discussion of the growth projections is in Section 9.1.2.2.

[b] The total fugitive emissions from Model Plants A, B, and C are derived from the emissions per model plant in Table 7-3. The sum of emissions in any one year is the sum of the products of the number of affected facilities per model plant times the emissions per model plant.

Implementation of Regulatory Alternatives II through IV would increase solid waste whenever equipment specifications require the replacement of existing equipment.

Implementation of Alternatives II through IV, however, would have an insignificant impact beyond existing levels (Regulatory Alternative I). This is because most gas plant solid waste is unrelated to the regulatory alternatives. These sources of solid waste include separator and tank sludges, filter cakes, and slop oil. Also, metal solid wastes (e.g., mechanical seals, rupture disks, caps, plugs, and valve parts) could be recycled and thus minimize any impact on solid waste.

7.5 ENERGY IMPACTS

Implementation of Regulatory Alternatives II through IV results in a net positive energy impact. The energy savings from the "recovered" emissions far outweigh the energy requirements of the alternatives. The regulatory alternatives would require a minimal increase in energy consumption due to: operation of monitoring instruments; installation of dual mechanical seals, which require a minimal increase in energy over single mechanical seals because of seal/shaft friction and operation of fluid flush system; operation of the compressor vent control system; closed loop sampling; and operation of combustion devices.

The energy savings over a 5-year period from new plants alone is estimated at 4,600 terajoules (Regulatory Alternative II) up to 4,900 terajoules (Regulatory Alternative IV) as shown in Table 7-5. Modified/reconstructed units may represent an additional 1,600 and 1,800 terajoules, respectively. Table 7-5 also shows the energy savings in crude oil equivalents.

7.6 OTHER ENVIRONMENTAL CONCERNS

7.6.1 Irreversible and Irretrievable Commitment of Resources

Implementation of any of the regulatory alternatives is not expected to result in any irreversible or irretrievable commitment of resources. Rather, implementation of Alternatives II through IV would save resources due to the energy savings associated with the reductions in emissions. As previously noted, the generation of solid waste used in the control equipment will not be significant.

Table 7-5. ENERGY IMPACTS OF EMISSION REDUCTIONS FOR REGULATORY ALTERNATIVES FOR 1983-1987

	Regulatory alternative	Five-year total recovered emissions from baseline (1000 Mg)[a]	Energy value of recovered emissions (terajoules)[b,c]	Crude oil equivalent of recovered emissions (1000 bbl)[d]
New plants	II	36 (88)	4,600	750
	III	37 (85)	4,400	720
	IV	40 (94)	4,900	800
Modified/ reconstructed plants	II	13 (31)	1,600	260
	III	13 (31)	1,600	260
	IV	14 (34)	1,800	290

xx = VOC emission values.

(xx) = Total hydrocarbon emission values.

[a] Estimated total fugitive emission reduction from Model Plants A, B, and C, from Table 7-4. Numbers are corrected to account for emissions not recovered due to venting of compressors to flares or heater fuel line in Regulatory Alternatives III and IV.

[b] Calculated on the basis of 47 terajoules per gigagram of VOC. Heating value is assumed to be equal to that of natural gas plant liquid production for 1978-1980 of 3,925,000 Btu/bbl (4.14 gigajoules/bbl), Reference 3. Specific gravity assumed to be 0.55, Reference 1.

[c] Calculated on the basis of 55 terajoules per gigagram of methane-ethane. Composition is assumed to be 80 percent methane and 20 percent ethane. The heats of combustion are assumed to be 23,000 Btu/lb and 22,300 Btu/lb for methane and ethane, respectively, Reference 2.

[d] Calculated on the basis of 163 bbl crude per terajoule. Heating value is assumed to be equal to that of crude petroleum production for 1978-1980 of 5,800,000 Btu/bbl, Reference 3.

7.6.2 Environmental Impact of Delayed Regulatory Action

As discussed in the above sections, implementation of the regulatory alternatives will not significantly impact water quality or solid waste. However, a delay in regulatory action would adversely impact air quality at the rate shown in Table 7-4.

7.7 REFERENCES

1. Nelson, W. L. Petroleum Refinery Engineering. McGraw-Hill Book Company, Inc. New York, 1958. p. 32. Docket Reference Number II-I-1.*

2. Perry, R. H., and C. H. Chilton, eds. Chemical Engineers' Handbook, Fifth Edition. McGraw-Hill Book Company, New York. 1973. p. 9-16. Docket Reference Number II-I-7.*

3. DOE Monthly Energy Review. January 1981. DOE/EIA-0035 (81/01). Docket Reference Number II-I-26.*

4. Memorandum, T.W. Rhoads, PES to Docket A-80-20-B. Evaluation of the Effects of Leak Detection and Repair on Fugitive Emissions in the Onshore Natural Gas Processing Industry Using the LDAR Model, November 1, 1982. Docket Reference Number II-B-18.*

5. Memorandum T.W. Rhoads, PES to Docket A-80-20-B. Calculation of Controlled Emission Factors for Pressure Relief Valves and Compressor Seals. November 1, 1982. Docket Reference Number II-B-17.*

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*References can be located in Docket Number A-80-20-B at U.S. Environmental Protection Agency Library, Waterside Mall, Washington, D.C.

8. COST ANALYSIS

8.1 COST ANALYSIS OF REGULATORY ALTERNATIVES

8.1.1 Introduction

The following sections present estimates of the capital costs, annual costs, and cost effectiveness for each model plant and regulatory alternative discussed in Chapter 6. These estimates will then be used in Chapter 9 to estimate the economic impact of the regulatory alternatives upon the natural gas/gasoline processing industry. To ensure a common cost basis, Chemical Engineering cost indices were used to adjust control equipment to June 1980 dollars.

8.1.2 New Facilities

8.1.2.1 Capital Costs. The bases for the capital costs for monitoring instruments and control equipment are presented in Table 8-1. These data are used to tabulate the capital costs for each model plant under the regulatory alternatives as given in Table 8-2.

Regulatory Alternative I requires no additional controls and therefore incurs no capital costs. Under Regulatory Alternatives II through IV, caps for open-ended lines and two monitoring instruments would be purchased. Although only one instrument is required, it is assumed that plant operators will purchase a spare in the event that the first becomes inoperable. There are no other capital costs associated with Alternative II.

Regulatory Alternative III also includes the cost of a compressor vent control system and closed-loop sampling connections. As shown in Figure 4-2, the compressor vent control system capital costs for reciprocating seals include venting the seal and distance piece emissions to either a flare or the plant heater as fuel gas. For centrifugal seals, the compressor vent control system capital costs include capturing the seal emissions from the seal degassing vent and similarly destroying

Table 8-1. CAPITAL COST DATA (June 1980 dollars)

1. Monitoring Instruments

   2 instruments (Foxboro OVA-108)
   @ $4,600/instrument[a]
   Total cost is $9,200/plant

2. Caps for Open-Ended Lines

   Based on cost for 5.1 cm screw-on gate valve, rated at 17.6 kg/cm² (250 psi) water, oil, gas (w.o.g.) pressure. June 1981 cost is $46.50[b], June 1980 cost is 8 percent less[c] at $43. Retrofit installation = 1 hour at $18/hour[d]. Total cost is $61/line.

3. Compressor Seal Vent Control System

A. Vent Manifold Piping[e]

2m	30cm pipe @ $108.00/m	$ 216.00	
100m	5.1cm pipe @ $6.50/m	650.00	
2	30 cm blind flanges @ $50	100.00	
	Total vent manifold and trap piping		$ 966

Labor[f]

$\frac{\text{102m of pipe}}{\text{30m/hr/crew}}$ = 3.4 hr for installation
2.5 hr for set-up/breakdown
5.0 hr for fabrication
10.9 hours/crew

10.9 crew hrs. x $\frac{\text{3 men}}{\text{crew}}$ x $18.00/hr =

total labor	$ 589	
total dollars		$ 1,555

B. Reciprocating Compressor Seal Piping[e]

1	double distance piece	$ 2,000.00[j]	
15m	2.5cm pipe @ $2.82/m	42.30	
5m	5.1cm pipe @ $6.50/m	32.50	
1	2.5cm tee @ $7.30	7.30	
2	5.1cm x 2.5cm tees @ $8.16	16.32	
3	2.5cm block valves @ $24.63	73.89	
1	2.5cm check valve @ $80.40	80.40	
3	2.5cm elbows @ $6.22	18.66	
1	pressure alarm @ $9.90[i]	9.90	
	Total manifold piping		$ 2,281

Table 8-1. CAPITAL COST DATA (June 1980 dollars)
(continued)

Labor[f]

$\frac{\text{20m of pipe}}{\text{30m/hr/crew}}$ = 1 hr for installation
0.75 hr for set-up/breakdown
1.5 hr for fabrication
3.25 hr/crew

$3.25 \text{ crew hrs. x } \frac{\text{3 men}}{\text{crew}} \text{ x } \$18.00/\text{hr} =$

total labor	$ 176		
total dollars		$ 2,456	

C. Centrifugal Compressor Seal Piping[e]

5m	2.5cm pipe @$2.82/m	$ 14.10		
5m	5.1cm pipe @ $6.50/m	32.50		
1	5.1cm x 2.5cm tees @ $8.16	8.16		
1	2.5cm block valves @ $24.63	24.63		
1	2.5cm elbows @ $6.22	6.22		
1	pressure alarm @ 9.90[i]	9.90		
	Total manifold piping		$ 96	

Labor[f]

$\frac{\text{10m of pipe}}{\text{30m/hr/crew}}$ = 0.33 hr for installation
0.25 hr for set-up/breakdown
0.5 hr for fabrication
1.08 hours/crew

$1.08 \text{ crew hrs. x } \frac{\text{3 men}}{\text{crew}} \text{ x } \$18.00/\text{hr} =$

	$ 58	
total dollars		$ 154

D. Gas Supply System Costs
Parts

5m	2.5 cm pipe @ $2.82/m	$ 14.10		
2	2.5 cm back valves @ $24.63	49.26		
1	pressure alarm @ $9.90[i]	9.90		
1	gas shutoff valve @ $23.89[i]	23.89		
	Total Parts		$ 97.15	
	Labor @ 100% Parts Price[k]		97.15	
	total dollars			$ 194

Table 8-1. CAPITAL COST DATA (June 1980 dollars)
(continued)

4. Closed-purge Sampling Connections[9]

Based on 6 m length of 2.5 cm schedule 40 carbon steel pipe, and three 2.5 cm ball valves. Retrofit or new installation = 18 hours at $18/hour. Total cost is $530/sampling connection.

5. Rupture Disk System with Block Valve[9]

New Installation

Rupture Disk Assembly				
7.6 cm rupture disk (stainless)	=	$ 230		
7.6 cm rupture disk holder (carbon steel)	=	384		
0.6 cm pressure gauge	=	18		
0.6 cm bleed gate valve	=	30		
Subtotal			$ 662	
Upstream Block Valve				
7.6 cm gate valve	=		$ 700	
Offset Mounting				
10.2 cm tee, elbow	=		$ 21	
Installation				
rupture disk assembly, 16 hrs @ $18/hr	=	$248		
upstream block valve, 10 hrs @ $18/hr	=	180		
offset mounting, 8 hrs @ $18/hr	=	144		
Subtotal			$ 612	
Total				$ 1,995

Table 8-1. CAPITAL COST DATA (June 1980 dollars)
(continued)

Retrofit Installation				
Relief Valve Replacement				
7.6 cm relief valve (stainless)	=	$1,456		
Installation, 10 hrs @ $18/hr	=	180		
Rupture Disk Assembly			$ 1,636	
			1,995	
Total				$3,631
6. Rupture Disk System with 3-Way Valve[h]				
New Installation				
Rupture Disk with 3-way Valve				
rupture disk assembly	=	$ 662		
One 3-way valve (7.6 cm, 2-port)	=	1,320		
One 7.6 cm pressure relief valve (stainless)	=	1,456		
Two 7.6 cm elbows	=	30		
Subtotal			$ 3,468	
Installation, 36 hrs @ $18/hr	=		648	
Total				$4,116
Retrofit Installation				
Rupture Disk with 3-way Valve	=		$ 3,468	
Installation, 72 hrs @ $18/hr	=		$ 1,296	
				$4,764
7. Dual Mechanical Seals[g]				
New Installation				
Seal cost	=	$1,250		
Seal credit	=	-278		
Installation, 16 hrs @ $18/hr	=	288		
Total			$ 1,260	
Retrofit Installation				
Seal cost	=	$ 1,250		
Installation, 19 hrs @ $18/hr	=	342		
Total			$ 1,592	
Barrier Fluid System for Dual Mechanical Seals (new or retrofit)			1,850	

Table 8-1. CAPITAL COST DATA (June 1980 dollars) (concluded)

Pump Seal Barrier Fluid Degassing Reservoir Vent (new or retrofit)	$ 4,000	
Total - new installation		$ 7,100
Total - retrofit installation		$ 7,388

[a] One instrument used as a spare. Cost is based on Reference 1.

[b] Reference 2.

[c] Cost adjustment based on the economic indicators for pipe, valves, and fittings in April 1980 (final) vs. April 1981 (preliminary). Reference 3.

[d] Reference 4.

[e] Reference 5.

[f] Reference 18.

[g] Reference 7.

[h] Reference 8.

[i] Reference 6.

[j] Reference 16.

[k] Engineering estimate.

Table 8-2. CAPITAL COST ESTIMATES FOR MODEL PLANTS
(thousands of June 1980 dollars)

Capital cost item	Regulatory Alternative			
	II[a]	III[a]	IV[b]	IV[c]
Model Plant A				
1. Monitoring instrument	9.2	9.2	9.2	9.2
2. Caps for open-ended lines	3.1	3.1	3.1	3.1
3. Compressor vent control system[d]		5.9	5.9	5.9
4. Closed-loop sampling connections		2.1	2.1	2.1
5. Rupture disk system[e]			12	17
6. Dual mechanical seals			14	15
Total	12	20	46	52

[a] Costs are the same for new or retrofit installation.

[b] New installation costs.

[c] Retrofit installation costs.

[d] Costs based on installed compressor seal vent control system for 50 percent reciprocating and 50 percent centrifugal compressors.

[e] Costs based on 50% rupture disk systems with block valve and 50% rupture disk systems with 3-way valve.

Table 8-2. CAPITAL COST ESTIMATES FOR MODEL PLANTS
(thousands of June 1980 dollars)
(Continued)

	Regulatory Alternative			
Capital cost item	II[a]	III[a]	IV[b]	IV[c]
Model Plant B				
1. Monitoring instrument	9.2	9.2	9.2	9.2
2. Caps for open-ended lines	9.2	9.2	9.2	9.2
3. Compressor vent control system[d]		11.1	11.1	11.1
4. Closed-loop sampling connections		6.4	6.4	6.4
5. Rupture disk system[e]			37	51
6. Dual mechanical seals			43	44
Total	18	36	116	131

[a] Costs are the same for new or retrofit installation.

[b] New installation costs.

[c] Retrofit installation costs.

[d] Costs based on installed compressor seal vent control system for 50 percent reciprocating and 50 percent centrifugal compressors.

[e] Costs based on 50% rupture disk systems with block valve and 50% rupture disk systems with 3-way valve.

Table 8-2. CAPITAL COST ESTIMATES FOR MODEL PLANTS
(thousands of June 1980 dollars)
(Concluded)

	Regulatory Alternative			
Capital cost item	II[a]	III[a]	IV[b]	IV[c]
Model Plant C				
1. Monitoring instrument	9.2	9.2	9.2	9.2
2. Caps for open-ended lines	31	31	31	31
3. Compressor vent control system[d]		29	29	29
4. Closed-loop sampling connections		21	21	21
5. Rupture disk system[e]			120	170
6. Dual mechanical seals			140	150
Total	40	90	350	410

[a] Costs are the same for new or retrofit installation.

[b] New installation costs.

[c] Retrofit installation costs.

[d] Costs based on installed compressor seal vent control system for 50 percent reciprocating and 50 percent centrifugal compressors.

[e] Costs based on 50 percent rupture disk systems with block valve and 50 percent rupture disk systems with 3-way valve.

the emissions. Table 8-1 shows the installed capital costs for the vent system piping arrangements. The model plant capital costs reported in Table 8-2 are based on the model unit number of compressors with 50 percent reciprocating and 50 percent centrifugal compressor seals. The costs given in Table 8-2 reflect two vent manifold systems and one gas supply system for each plant, in addition to the required number of centrifugal and reciprocating seal piping systems.

Alternative IV includes all the costs of Alternative III plus the costs of a rupture disk for pressure system relief valves and dual mechanical seals for pumps. The costs of Regulatory Alternative IV are different for new installation of equipment and for retrofit installations.

8.1.2.2 Annual Costs. Implementation of Regulatory Alternatives II through IV would require visual and/or instrument monitoring of potential VOC emissions. The inspection requirements are given in Chapter 6. Table 8-3 summarizes the leak detection and repair labor-hour requirements, and Table 8-4 shows the annual costs for the alternatives by model plant. These repair costs cover the expense of repairing those components in which leaks develop after initial repair. The cost for leak detection and repair labor was assumed to be $18.00 per hour.

Administrative and support costs were estimated at 40 percent of the sum of leak detection and repair labor costs. Leak detection labor, leak repair labor, and administrative/support costs are recurring annual costs for each regulatory alternative.

8.1.2.3 Annualized Costs. The bases for the annualized control costs are presented in Table 8-5. The annualized capital, maintenance, and miscellaneous costs were calculated by taking the appropriate factor from Table 8-5 and applying it to the corresponding capital cost from Table 8-2. The capital recovery factors were calculated using the equation:

$$\mathrm{CRF} = \frac{i(1+i)^n}{(1+i)^n - 1}$$

Where i = interest rate, expressed as a decimal,

n = economic life of the component, years.

The interest rate used was 10 percent. The expected life of the monitoring instrument was 6 years. Dual mechanical seals and rupture

TABLE 8-3. LEAK DETECTION AND REPAIR LABOR-HOUR REQUIREMENTS

					Leak detection					Leak repair								
Component type	Monitoring interval	Components per model plant			Type of monitoring[a]	Times monitored per year	Monitoring labor-hours required[b,c]			Fraction of sources maintained	Estimated number of leaks per year			Repair time per source (hours)	Maintenance labor-hours[f]		
		A	B	C			A	B	C		A	B	C		A	B	C
Valves	quarterly	250	750	2,500	instrument	4.0[h,g]	33	100	333	0.185[g]	46	139	464	1.13[i]	52	157	524
	monthly/ quarterly				instrument	4.3[h,g]	36	108	358	0.187[g]	47	140	467		53	158	528
	monthly				instrument	11.9[h,g]	99	298	992	0.191[g]	48	143	478		54	162	540
Relief valves	quarterly	4	12	40	instrument	4	4.3	13	43	0.08[e]	0.3	1.3	3.2	0[j]	0	0	0
	monthly				instrument	12	13	38	130	0.11[e]	0.4	1.3	4.4		0	0	0
Compressor seals	quarterly	2	6	20	instrument	4	1.3	4.0	13	0.17[e]	0.3	1.0	3.4	40[k]	12	40	136
Pump seals	quarterly	2	6	20	instrument	4[g]	1.3	4.0	13	0.394[g]	0.79	2.4	7.9	16[k]	12.6	38	126
	monthly				instrument	12[g]	4.0	12	40	0.408[g]	0.82	2.5	8.2		13.1	40	131
	weekly				visual	52	0.9	2.6	8.7								

[a] Assumes that instrument monitoring requires a two-person team, and visual monitoring, one person.

[b] Monitoring time per person: pumps-instrument 5 min., visual 1/2 min.; compressors 5 min.; valves 1 min., and safety/relief valves 8 min. Reference 10.

[c] Monitoring labor-hours = number of workers x number of components x time to monitor x times monitored per year.

[d] Based on the number of sources leaking at 10,000 ppmv. From Table 4-1.

[e] Annual percent recurrence factors have been applied for monthly and quarterly instrument inspections for relief valves and compressor seals to determine the percentage of sources maintained. It is assumed that 5 percent of leaks initially detected are found with monthly monitoring (0.05 x 12 = 0.6) and that 10 percent of leaks initially detected are found with quarterly monitoring (0.1 x 4 = 0.4). Fraction of sources initially leaking from Table 4-1. Number of leaks = number of components x fraction of sources initially leaking x annual fraction of recurrence factor. Reference 7.

[f] Leak repair labor-hours = number of leaks x repair time.

[g] The values used in calculating labor-hour requirements for valves and pump seals were developed on the basis of the model and data presented in Appendix E.

[h] Fractional numbers accounted for by recognizing that it is not necessary to monitor valves that have previously been identified as leakers and have not yet been repaired.

[i] Weighted average based on 75 percent of the leaks repaired on-line, requiring 0.17 hours per repair, and on 25 percent of the leaks, repaired offline, requiring 4 hours per repair. Reference 9.

[j] It is assumed that these leaks are corrected by routine maintenance at no additional labor requirements. Reference 10.

[k] References 10 and 17.

Table 8-4. ANNUAL LEAK DETECTION AND REPAIR LABOR COSTS[a]
(June 1980 dollars)

Regulatory alternative[b]	Leak detection cost model plant			Repair cost model plant		
	A	B	C	A	B	C
II[c]	730	2,200	7,400	1,400	4,300	14,000
III[d]	970	2,900	9,700	1,200	3,600	12,000
IV[e]	1,800	5,400	18,000	970	2,900	9,700

[a] Costs = labor-hours (Table 8-3) x $18/hour (Table 8-5).

[b] Regulatory Alternative I (baseline control) has zero costs.

[c] Calculated on the basis of quarterly instrument monitoring for valves, relief valves, compressor seals, and pump seals, and weekly visual monitoring for pump seals.

[d] Calculated on the basis of monthly/quarterly instrument monitoring for valves, monthly instrument monitoring for relief valves and pump seals, and weekly visual monitoring for pump seals.

[e] Calculated on the basis of monthly monitoring of valves.

disks were assumed to have a 2-year life. All other control equipment is assumed to have a 10-year life.

For the purposes of determining recovery credits, the value of VOC is assumed to be $192/Mg, and the value of methane-ethane is assumed to be $61/Mg. The derivation of these values is described in Table 8-5. Although compressor emissions can be routed to the process heater, resulting in a fuel savings, no credit is taken because most plants are likely to combust these organics in a flare.

Implementation of Regulatory Alternatives II, III, and IV involves initial detection and repair of leaking components. As shown in Table 8-6, the repair labor-hour requirements of the initial survey are derived by multiplying the fraction of sources leaking and repair time per source by the model plant component counts. The cost of repairing initial leaks was amortized over a 10-year period, since this is a one-time cost. Administrative and support costs to implement the regulatory alternatives were assumed to be 40 percent of the leak detection and repair labor costs. Table 8-7 shows the initial leak repair costs. These costs include the labor costs from Table 8-6, and replacement mechanical pump seals. The initial leak repair cost in Table 8-7 shows Alternative II to be the most costly. Costs decrease for the other alternatives as equipment specifications replace the labor intensive equipment repairs.

8.1.2.4 Recovery Credits. The annual emissions, total emissions recovered, and annual recovered product credits for each model plant and regulatory alternative appear in Table 8-8. Regulatory Alternative I represents "baseline emissions" and therefore receives no recovery credits.

8.1.2.5 Net Annual Costs. The net annual model plant costs shown in Tables 8-9, 8-10, and 8-11 were determined by subtracting the annual recovered product credit from the total cost before credit. For example, Model Plant A under Regulatory Alternative II has a net annual cost of $3,800, as a result of $9,700 in costs and $5,900 in recovery credits.

8.1.2.6 Cost Effectiveness. The cost effectiveness of the regulatory alternatives for each model plant is shown in Table 8-12. Regulatory Alternatives II and III for all model plants entail

Table 8-5. DERIVATION OF ANNUALIZED LABOR, ADMINISTRATIVE, MAINTENANCE, AND CAPITAL COSTS

1. Capital recovery factor for capital costs	
o Dual mechanical seals and rupture disks	0.58 x capital[a]
o Other control equipment	0.163 x capital[b]
o Monitoring instruments	0.23 x capital[c]
2. Annual maintenance costs	
o Control equipment	0.05 x capital[d]
o Monitoring instruments	$3,000[e]
o Replacement pump seals	$140[m]
3. Annual miscellaneous costs	0.04 x capital[f]
4. Labor costs	$18/hr[g]
5. Administrative and support costs to implement regulatory alternative	0.40 x (monitoring labor + maintenance labor)[d]
6. Annualized charge for initial leak repairs	(estimated number of leaking components per model unit[i] x repair time) x $18/hr[h] x 1.4 x 0.163
7. Recovery credits	
o Nonmethane-nonethane hydrocarbons (VOC)	$192/Mg[k]
o Methane-ethane	$ 61/Mg[l]

[a] Applies to cost of seals ($972-incremental cost due to specification of dual seals instead of single seals) and disk ($230) only. Two year life, ten percent interest. Reference 7.

[b] Ten year life, ten percent interest. Reference 11.

[c] Six year life, ten percent interest. Reference 11.

[d] From Reference 11.

[e] Includes materials and labor for maintenance and calibration.

[f] Reference 11.

[g] Includes wages plus 40 percent for labor-related administrative and overhead costs. Reference 11.

[h] From Reference 4.

[i] Shown in Table 8-3.

[j] Initial leak repair amortized for ten years at ten percent interest.

[k] Based on LPG price of 40¢/gallon for June 1980 (Reference 13) and specific gravity of 0.55 (Reference 14).

[l] Based on natural gas price of $1.46/Mcf for June 1980 (Reference 15) and assumed composition of 80% methane and 20% ethane at standard temperature and pressure.

[m] Reference 17, corrected to June 1980.

TABLE 8-6. LABOR-HOUR REQUIREMENTS FOR INITIAL LEAK REPAIR

Component type	Number of components per model plant			Percent of sources leaking in Initial survey[a]	Estimated Number of leaks			Repair time per source[b] (hours)	Repair labor-hours		
	A	B	C		A	B	C		A	B	C
Valves	250	750	2,500	18	45	135	450	1.13	51	153	509
Relief valves	4	12	40	19	0.76	2.3	7.6	0	0	0	0
Compressor seals	2	6	20	43	0.86	2.6	8.6	40	34	104	344
Pump seals	2	6	20	33	0.66	2.0	6.6	16	11	32	106

[a] Based on the number of sources leaking at 10,000 ppm from Table 4-1.

[b] See Table 8-3.

Table 8-7. INITIAL LEAK REPAIR COSTS (JUNE 1980 DOLLARS)

Regulatory alternative[a]	Initial repair costs for model plants[b]			Annualized initial repair costs for model plants[c]		
	A	B	C	A	B	C
II	2,400	7,300	24,000	390	1,200	4,000
III	1,600	4,700	16,000	260	770	2,500
IV	1,300	3,900	13,000	210	640	2,100

[a] Regulatory Alternative I (baseline control) has zero costs.

[b] Costs = labor-hours (Table 8-6) x $18/hour (Table 8-5) x 1.4 (Administrative costs, Table 8-5) + new seal costs for pumps.

[c] Annualized cost = Initial Repair Costs x 0.163 (capital recovery factor, Table 8-5).

Table 8-8. RECOVERY CREDITS

Regulatory alternative	Model Plant A		Model Plant B		Model Plant C	
	Recovered emissions,[a] Mg/yr	Recovered product value,b $/yr	Recovered emissions,[a] Mg/yr	Recovered product value,b $/yr	Recovered emissions,[a] Mg/yr	Recovered product value,b $/yr
II	20.6 (52)	5,870	62 (113)	15,000	205 (510)	58,000
III	20.3 (49)	5,650	61 (147)	17,000	201 (489)	56,200
IV	22 (54)	6,180	66 (161)	18,500	215 (539)	61,000

xx = VOC emission values.

(xx) = Total hydrocarbon emission values.

[a] Based on emission reductions presented in Table 7-2 and 7-3.

[b] Based on recovered VOC value of $192/Mg, and recovered non-VOC hydrocarbon (methane-ethane) value of $61/Mg from Table 8-5. No recovery credits are given for compressors. Compressor seal vent emissions could be used as process heater fuel resulting in recovery of these emissions at their fuel value.

Example Calculation for Model Plant A, Regulatory Alternative IV:

Recovered Product Value ($/yr) = (22 Mg/yr VOC) ($192/Mg VOC) + (54 Mg/yr THC - 22 Mg/yr VOC) ($61/Mg C_1, C_2) = $6,180

Table 8-9. ANNUAL COST ESTIMATES FOR MODEL PLANT A (Thousands of June 1980 Dollars)

Cost Item	Regulatory Alternative			
	II[a]	III[a]	IV[b]	IV[c]
Annualized Capital Costs				
A. Control equipment[d]				
1. Monitoring instruments	2.1	2.1	2.1	2.1
2. Caps for open-ended lines	0.51	0.51	0.51	0.51
3. Compressor vent control system		0.96	0.96	0.96
4. Closed-loop sampling connections		0.34	0.34	0.34
5. Rupture disk system			2.4	3.1
6. Dual mechanical seal system			3.1	3.5
B. Initial leak repair[e]	0.39	0.26	0.21	0.21
Operating Costs				
A. Maintenance costs[f]				
1. Monitoring instruments	3.0	3.0	3.0	3.0
2. Caps for open-ended lines	0.16	0.16	0.16	0.16
3. Compressor vent control system		0.30	0.30	0.30
4. Closed-loop sampling connections		0.10	0.10	0.10
5. Rupture disk system			0.60	0.85
6. Dual mechanical seals			0.71	0.74
7. Replacement seal system	0.11	0.11		
B. Miscellaneous costs[f]				
1. Monitoring instruments	0.37	0.37	0.37	0.37
2. Caps for open-ended lines	0.12	0.12	0.12	0.12
3. Compressor vent control system		0.24	0.24	0.24
4. Closed-loop sampling connections		0.08	0.08	0.08
5. Rupture disk system			0.48	0.68
6. Dual mechanical seal system			0.57	0.60
C. Labor charges				
1. Monitoring labor[g]	0.73	0.97	1.8	1.8
2. Leak repair labor[g]	1.4	1.2	0.97	0.97
3. Administrative and support[f]	0.85	0.87	1.1	1.1
Total Before Credit	9.7	12	20	22
Recovery Credits[h]	(5.9)	(5.7)	(6.2)	(6.2)
Net Annual Cost	3.8	6.3	14	16

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[a] Costs are the same for new or modified/reconstructed facilities ( ) = cost savings.

[b] Costs for new facilities.

[c] Costs for modified/reconstructed facilities.

[d] Capital costs from Table 8-2. Capital recovery factor from Table 8-5.

[e] From Table 8-7.

[f] From Table 8-5

[g] From Table 8-4.

[h] From Table 8-8.

Table 8-10. ANNUAL COST ESTIMATES FOR MODEL PLANT B
(Thousands of June 1980 Dollars)

Cost Item	Regulatory Alternative			
	II[a]	III[a]	IV[b]	IV[c]
Annualized Capital Costs				
A. Control equipment[d]				
1. Monitoring instruments	2.1	2.1	2.1	2.1
2. Caps for open-ended lines	1.5	1.5	1.5	1.5
3. Compressor vent control system		1.8	1.8	1.8
4. Closed-loop sampling connections		1.0	1.0	1.0
5. Rupture disk system			7.1	9.4
6. Dual mechanical seals			9.4	10
B. Initial leak repair[e]	1.2	0.77	0.64	0.64
Operating Costs				
A. Maintenance costs				
1. Monitoring instruments[f]	3.0	3.0	3.0	3.0
2. Caps for open-ended lines	0.46	0.46	0.46	0.46
3. Compressor vent control system		0.55	0.55	0.55
4. Closed-loop sampling connections		0.32	0.32	0.32
5. Rupture disk system			1.9	2.6
6. Dual mechanical seals			2.1	2.2
7. Replacement pump seals	0.34	0.35		
B. Miscellaneous costs[f]				
1. Monitoring instruments	0.37	0.37	0.37	0.37
2. Caps for open-ended lines	0.37	0.37	0.37	0.37
3. Compressor vent control system		0.44	0.44	0.44
4. Closed-loop sampling connections		0.26	0.26	0.26
5. Rupture disk system			1.5	2.0
6. Dual mechanical seals			1.7	1.8
C. Labor charges				
1. Monitoring labor[g]	2.2	2.9	5.4	5.4
2. Leak repair labor[g]	4.3	3.6	2.9	2.9
3. Administrative and support[f]	2.6	2.6	3.3	3.3
Total Before Credit	19	22	48	52
Recovery Credits[h]	(15)	(17)	(19)	(19)
Net Annual Cost	4	5	29	33

[a] Costs are the same for new or modified/reconstructed facilities.

[b] Costs for new facilities.

[c] Costs for modified/reconstructed facilities.

[d] Capital costs from Table 8-2. Capital recovery factor from Table 8-5.

[e] From Table 8-7.

[f] From Table 8-5

[g] From Table 8-4.

[h] From Table 8-8.

Table 8-11. ANNUAL COST ESTIMATES FOR MODEL PLANT C
(Thousands of June 1980 Dollars)

Cost Item	Regulatory Alternative			
	II[a]	III[a]	IV[b]	IV[c]
Annualized Capital Costs				
A. Control equipment[d]				
1. Monitoring instruments	2.1	2.1	2.1	2.1
2. Caps for open-ended lines	5.0	5.0	5.0	5.0
3. Compressor vent control system		4.7	4.7	4.7
4. Closed-loop sampling connections		3.4	3.4	3.4
5. Rupture disk system			24	31
6. Dual mechanical seals			31	35
B. Initial leak repair[e]	4.0	2.5	2.1	2.1
Operating Costs				
A. Maintenance costs[f]				
1. Monitoring instruments	3.0	3.0	3.0	3.0
2. Caps for open-ended lines	1.5	1.5	1.5	1.5
3. Compressor vent control system		1.4	1.4	1.4
4. Closed-loop sampling connections		1.0	1.0	1.0
5. Rupture disk system			6.1	8.4
6. Dual mechanical seals			7.1	7.4
7. Replacement pump seals	1.1	1.1		
B. Miscellaneous costs[f]				
1. Monitoring instruments	0.37	0.37	0.37	0.37
2. Caps for open-ended lines	1.2	1.2	1.2	1.2
3. Compressor vent control system		1.2	1.2	1.2
4. Closed-loop sampling connections		0.84	0.84	0.84
5. Rupture disk system			4.8	6.8
6. Dual mechanical seals			5.7	6.0
C. Labor charges				
1. Monitoring labor[g]	7.4	9.7	18	18
2. Leak repair labor[g]	14	12	9.7	9.7
3. Administrative and support[f]	8.6	8.7	11	11
Total Before Credit	48	59	145	161
Recovery Credits[h]	(58)	(56)	(61)	(61)
Net Annual Cost	(10)	3	84	100

[a] Costs are the same for new or modified/reconstructed facilities.

[b] Costs for new facilities.

[c] Costs for modified/reconstructed facilities.

[d] Capital costs from Table 8-2. Capital recovery factor from Table 8-5.

[e] From Table 8-7.

[f] From Table 8-5

[g] From Table 8-4.

[h] From Table 8-8.

Table 8-12. COST EFFECTIVENESS OF REGULATORY ALTERNATIVES

	Regulatory Alternative				
	I	II[a]	III[a]	IV[b]	IV[c]
Model Plant A					
Capital Cost ($)[d]	0	12,000	20,000	46,000	52,000
Net annual cost ($/yr)[e]	0	3,800	6,300	14,000	16,000
Total VOC reduction (Mg/yr)[f]	0	20.6	21.0	22.4	22.4
Cost effectiveness ($/Mg VOC)[g]	0	180	300	630	710
Model Plant B					
Capital Cost ($)[d]	0	18,000	36,000	116,000	131,000
Net annual cost ($/yr)[h]	0	4,000	5,000	29,000	33,000
Total VOC reduction (Mg/yr)[f]	0	62	63	68	68
Cost effectiveness ($/Mg VOC)[g]	0	65	79	430	490
Model Plant C					
Capital Cost ($)[d]	0	40,000	90,000	350,000	410,000
Net annual cost ($/yr)[i]	0	(10,000)	3,000	84,000	100,000
Total VOC reduction (Mg/yr)[f]	0	200	210	220	220
Cost effectiveness ($/Mg VOC)[g]	0	(50)	14	380	450

[a] Costs are the same for new or modified/reconstructed facilities.

[b] Costs for new facilities.

[c] Costs for modified/reconstructed facilities.

[d] From Table 8-1.

[e] From Table 8-9.

[f] From Table 7-3.

[g] Cost effectiveness = total VOC emission reduction divided by the net annual cost.

[h] From Table 8-10.

[i] From Table 8-11.

relatively low costs per Mg of VOC emission reduction when compared to Alternative IV. Model Plant B Regulatory Alternative II and Model Plant C Regulatory Alternatives II and III have a net annual credit.

8.1.3 Modified/Reconstructed Facilities

8.1.3.1 Capital Costs. The bases for determining the capital costs for modified/reconstructed facilities are presented in Table 8-1. The capital cost for Alternatives I, II, and III are the same as for new plants. However, the capital cost for Regulatory Alternative IV is higher than for new plants. This is because of the additional costs incurred through replacement of relief valves, and retrofit installation of dual mechanical seals.

8.1.3.2 Annual Costs. The annual control costs for modified/reconstructed plants are derived from the same basis as new plants (see Table 8-5). The net annual costs for modified/reconstructed facilities are higher than for new facilities under Regulatory Alternative IV (I, II, and III are the same as new facilities), as shown in Tables 8-9, 8-10, and 8-11. The recovery credits remain the same as for new plants.

8.1.3.3 Cost Effectiveness. The cost effectiveness of Regulatory Alternative IV for modified/reconstructed facilities is also shown in Table 8-12. The cost effectiveness of this Alternative is substantially higher than for new facilities.

8.1.4 Projected Cost Impacts

The projected fifth year industry wide costs of implementing the regulatory alternatives are presented in Table 8-13. The cost estimates were obtained by multiplying the costs per model plant by the model plant growth estimates given in Table 7-4 for 1983 to 1987. The cost impacts for new plants and modified/reconstructed plants are reported separately in order to differentiate between expected impacts, represented by new plants, and maximum impacts, represented by new plants with the addition of modified/ reconstructed plant impacts. A maximum impact would result if all changes to existing plants constitute modification/ reconstruction. The total capital costs reflect the cumulative costs of implementing the regulatory alternatives in a given year. All other costs shown are for plants subject to new source performance standards in the indicated year.

Table 8-13. FIFTH-YEAR NATIONWIDE COSTS OF THE REGULATORY ALTERNATIVES
(thousands of June 1980 dollars)

Cost item	II	III	IV
New plants[a]			
Cumulative capital costs by 1987	3,200	6,500	21,000
Total annual costs	3,400	4,000	9,700
Total recovery credit	2,700	3,100	3,400
Net annual costs	700	900	6,300
Modified/reconstructed facilities[a]			
Cumulative capital costs by 1987	990	2,100	8,600
Total annual costs	1,100	1,300	4,200
Total recovery credits	1,200	1,200	1,300
Net annual costs	(100)	100	2,900

( ) = cost savings

[a] A schedule of projected new and modified/reconstructed model plants is presented in Table 7-4.

8.2 OTHER COST CONSIDERATIONS

Environmental, safety, and health statutes that may cause an outlay of funds by the gas processing industry are listed in Table 8-14. Specific costs to the industry to comply with the provisions, requirements, and regulations of the statutes are unavailable.

Table 8-14 STATUTES THAT MAY BE APPLICABLE TO THE NATURAL GAS PROCESSING INDUSTRY

Statute	Applicable provision, regulation or requirement of statute
Clean Air Act and Admendments	o State implementation plans
	o National emission standards for hazardous air pollutants
	o New source performance standards
	o PSD construction permits
	o Nonattainment construction permits
Clean Water Act (Federal Water Pollution Act)	o Discharge permits
	o Effluent limitations guidelines
	o New source performance standards
	o Control of oil spills and discharges
	o Pretreatment requirements
	o Monitoring and reporting
	o Permitting of industrial projects that impinge on wetlands or public waters
	o Environmental impact statements
Resource Conservation and Recovery Act	o Permits for treatment, storage, and disposal of hazardous wastes
	o Establishes system to track hazardous wastes
	o Establishes recordkeeping, reporting, labeling, and monitoring system for hazardous waste
	o Superfund
Toxic Substances Control Act	o Premanufacture notification
	o Labeling, recordkeeping
	o Reporting requirements
	o Toxicity testing

Statute	Applicable provision, regulation or requirement of statute
Occupational Safety & Health Act	o Walking-working surface standards
	o Means of egress standards
	o Occupational health and environmental control standards
	o Hazardous material standards
	o Personal protective equipment standards
	o General environmental control standards
	o Medical and first aid standards
Coastal Zone Management Act	o Fire protection standards
National Environmental Policy Act	o Compressed gas and compressed air equipment
Safe Drinking Water Act	o Welding, brazing, and cutting standards
Marine Sanctuary Act	o States may veto Federal permits for plants to be sited in coastl zone
	o Requires environmental impact statements
	o Requires undergrond injection control permits
	o Ocean dumping permits
	o Recordkeeping and reporting

8.3 REFERENCES

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4. Letter with attachments from Texas Chemical Council to Walt Barber, U.S. EPA. June 30, 1980. Docket Reference Number II-D-4.*

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6. Telephone conversation. Tom Norwood, Pacific Environmental Services, Inc., with W.W. Grainger, Inc., Raleigh, NC. December 17, 1981. Costs of pressure switches and gas shutoff valves. Docket Reference Number II-E-18.*

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18. McMahon, Leonard A., 1981 Dodge Guide. Annual Edition No. 13, McGraw-Hill Publishing Co. Docket Reference Number II-I-125.*

*References can be located in Docket Number A-80-20-B at the U.S. Environmental Protection Agency Library, Waterside Mall, Washington, D.C.

9. ECONOMIC ANALYSIS OF THE REGULATORY ALTERNATIVES

9.1 INDUSTRY PROFILE

This section describes the general business and economic conditions of the onshore natural gas production industry. The primary focus of the discussion is on the natural gas processing segment of the industry for which alternative emission regulations are being considered.

Projections for the year 1987, five years after a proposal date of 1982 for the regulatory alternatives for new, modified or reconstructed sources, were developed for the industry. The growth projections are presented to illustrate the future trend of the industry. The profile and the projections, including significant factors and trends in the industry, are presented to aid in the determination of economic impacts of the proposed standards. The energy and environmental impact analyses also were conducted based upon these projections. The economic impacts are described in subsequent sections.

9.1.1 Onshore Natural Gas Production Industry

The natural gas system in the United States consists of producers, processors, dealers, interstate and intrastate pipelines, distributors and consumers. The production industry includes hundreds of firms engaged in the exploration, drilling, producing and processing of natural gas. A relatively small number of companies dominate the industry. The American Association of Petroleum Geologists (AAPG) states that the 16 largest firms in the industry found 53.7 percent of 2.8 billion barrels of crude oil and 40.3 percent of 41.3 trillion cubic feet of natural gas discovered during the period from 1969 to 1978. Also, the AAPG states that the 16 largest companies accounted for about 60 percent of industry expenditures for geological and geophysical information and lease acquisition. However, these large companies spend almost twice as much money as smaller firms on predrilling exploration and one-half as much as the others on wildcat drilling.[1]

Approximately two-thirds of all processed gas is transmitted in pipelines across state lines to be sold in various metropolitan areas. The remainder is sold in intrastate markets. Approximately 100 pipeline companies operate the interstate pipeline network. The pipeline sector of the industry tends to be dominated by large companies more than the production sector. In 1971, the four largest pipeline companies accounted for 35 percent of the total interstate pipeline volume, while the 20 largest companies transported over 93 percent of the gas.

Companies involved in the final distribution of the gas constitute the least concentrated sector of the industry. Over 1,600 companies buy gas from pipelines and distribute it to various communities. Because they operate in different service areas, these companies rarely compete with one another, except in input markets, and are often regulated by state or local agencies.

There is some vertical integration in the industry with pipeline companies often owning producing wells. However, few companies engage in production, transmission and distribution of the gas. In contrast, horizontal integration is quite extensive. In the production sector, almost all companies produce crude oil and natural gas liquids in addition to natural gas although no one company predominates. In addition, many also have investments in coal, oil shale, synfuels and mineral industries.

9.1.1.1 Natural Gas Processing Facilities. In 1980, there were 772 gas processing plants in the United States, with a combined total capacity of approximately 71.2 billion cubic feet per day. As of January 1, 1980, these plants were utilizing about 63 percent of their combined capacity. Table 9-1 presents a distribution of the gas plants based on their capacity. As this table indicates, at least 60 percent of the plants have capacities of 50 million cubic feet per day (MMcfd) or less. Another 16.8 percent of the plants have capacities between 50 MMcfd and 100 MMcfd. The remainder of the gas plants have capacities greater than 100 MMcfd, ranging as high as 2,650 MMcfd.

Table 9-1. DISTRIBUTION OF GAS PLANTS BY CAPACITY[a] (1980)

Plant Capacity (MMcfd)	Number of Plants
- 50	460
51 - 100	130
100 - 200	70
201 - 300	34
301 - 400	9
401 - 500	3
501 - 600	7
601 - 700	0
701 - 800	2
801 - 900	6
901 - 1,000	6
> 1,000	6
No Response	39
TOTAL	772

[a] Based on data presented in Oil and Gas Journal, July 14, 1980.

There are a number of different process methods currently being used at natural gas processing plants: adsorption, refrigerated absorption, refrigeration, compression, adsorption, cryogenic--Joule-Thomson and cryogenic-expander. The distribution of gas plants by these process methods and combinations of these methods is presented in Table 9-2.

In 1980, there were 138 different companies operating gas processing plants in the United States. Table 9-3, which shows the distribution of gas plants by ownership, lists the companies that own more than 20 plants. This table indicates that over 55 percent of the gas plants are owned by these "larger" companies. Also, Table 9-3 indicates that almost 85 percent of the 138 companies own less than ten gas plants.

All the gas plants in the United States in 1980 were located in twenty-two states, including two plants in Alaska. Table 9-4 shows a distribution of gas plants based on location and ranked in order of gas plant capacity. As the table indicates, over 46 percent of the plants are located in Texas. States not listed in Table 9-4 have less than ten gas plants.

9.1.1.2 Markets. Although the natural gas component of total energy production has decreased from 40 percent in 1973 to 34 percent in 1980 as indicated in Table 9-5, the natural gas production industry is expected to continue to supply a significant fraction of total domestic energy requirements. Exploration and production activities for natural gas are anticipated to continue to increase as a result of phased natural gas price deregulation and expected price increases.

Imports of natural gas have remained fairly constant since 1973, ranging from 953 billion cubic feet in 1975 to 1,253 billion cubic feet in 1979. Imports were 984 billion cubic feet in 1980 representing 4 percent of domestic consumption. Exports of natural gas declined from 77 billion cubic feet in 1973 to 49 billion cubic feet in 1980. Exports are primarily to Japan and Mexico. Imports are primarily from Canada, Mexico, and Algeria.

Domestic aggregate retail price elasticities of demand for solid fuels, natural gas, electricity and petroleum are shown in Table 9-6. These elasticities represent the change in final demand for each fuel with

Table 9-2. DISTRIBUTION OF GAS PLANTS BY PROCESS METHOD[a] (1980)

Process Method	Number of Plants
Absorption	77
Refrigerated Absorption	280
Refrigeration	161
Compression	7
Adsorption	40
Cryogenic-Joule-Thomson	19
Cryogenic-Expander	147
Absorption & Refrigerated Absorption	2
Absorption & Compression	1
Refrigerated Absorption & Refrigeration	2
Refrigerated Absorption & Adsorption	1
Refrigerated Absorption & Cryogenic-Joule-Thomson	2
Refrigerated Absorption & Cryogenic-Expander	13
Refrigeration & Compression	1
Refrigeration & Cryogenic-Joule-Thomson	1
Cryogenic-Joule-Thomson & Expander	10
No Response	8
TOTAL	772

[a] Based on data presented in Oil and Gas Journal, July 14, 1980.

Table 9-3. DISTRIBUTION OF GAS PLANTS BY OWNERSHIP[a] (1980)

Company Owner	Number of Plants
Amoco Production Company	47
Cities Service Company	41
Phillips Petroleum Company	37
Warren Petroleum Company	35
Exxon Company	33
Shell Oil Company	33
Sun Gas Company	33
Getty Oil Company	26
Mobil Oil Corporation	26
Texaco, Inc.	25
ARCO Oil and Gas Company	24
Chevron USA, Inc.	23
Union Oil Company of California	23
Mitchell Energy & Development Corporation	22
Number of companies that own between 10 and 20 plants	7
Number of companies that own less than 10 plants	117
Total number of companies that own gas plants	138
TOTAL	772

[a] Based on data presented in Oil and Gas Journal, July 14, 1980.

Table 9-4 DISTRIBUTION OF GAS PLANTS BY STATE[a] (1980)

State	Number of plants	Plant capacity (MMcfd)
Texas	356	24,646.9
Louisiana	103	24,566.7
Kansas	26	5,320.9
Oklahoma	86	4,267.7
New Mexico	34	3,632.1
Wyoming	40	1,357.7
California	37	1,254.5
Colorado	27	799.6
All other states	63	5,346.5
TOTAL	772	71,192.6

[a] Based on data presented in Oil and Gas Journal, July 14, 1980.

Table 9-5. PRODUCTION OF ENERGY BY TYPE, UNITED STATES (Quadrillion Btu)

	Coal[1]	Crude oil[2]	NGPL[3]	Natural gas (dry)	Hydro-electric power[4]	Nuclear electric power	Other[5]	Total energy produced	% NG of total
1973	14.366	19.493	2.569	22.187	2.861	0.910	0.046	62.433	40
1974	14.468	18.575	2.471	21.210	3.177	1.272	0.056	61.229	39
1975	15.189	17.729	2.374	19.640	3.155	1.900	0.072	60.059	37
1976	15.853	17.262	2.327	19.480	2.976	2.111	0.081	60.091	36
1977	15.829	17.454	2.327	19.565	2.333	2.702	0.082	60.293	36
1978	15.037	18.434	2.245	19.485	2.958	2.977	0.068	61.204	36
1979	17.651	18.104	2.286	20.076	2.954	2.748	0.089	63.907	35
1980	18.877	18.250	2.263	19.754	2.913	2.704	0.114	64.876	34

Totals may not equal sum of components due to independent rounding.

[1] Includes bituminous coal, lignite and anthracite.
[2] Includes lease condensate.
[3] Natural gas plant liquids.
[4] Includes industrial and utility production of hydropower.
[5] Includes geothermal power and electricity produced from wood and waste.

R = Revised data

Source: U.S. Department of Energy, Energy Information Administration calculations. Monthly Energy Review, July 1981.

Table 9-6. AGGREGATE RETAIL PRICE ELASTICITIES OF DEMAND, U.S.
(Estimate for 1985)

	Price elasticity of demand			
With respect to	Solid fuels	Natural gas	Electricity	Petroleum
Solid fuels	-.215	.030	.131	.031
Natural gas	.005	-.426	.228	.062
Electricity	.011	.052	-.376	.111
Petroleum	.002	.013	.077	-.263

Source: The Global 2000 Report to the President,(Volume III: Documentation), A report prepared by the Council on Environmental Quality and the Department of State. April 1981. p. 301.

respect to a change in the price of all four aggregate fuel types. Therefore, the diagonal corresponding to direct price elasticity should have a negative sign. For example, the domestic retail price elasticity for natural gas is -.426, indicating an inelastic aggregate retail demand. Electricity has the highest cross price elasticity with respect to natural gas with a value of .228, indicating that a one percent increase in the retail natural gas price causes a .228 percent increase in the aggregate quantity demanded of electricity. All of the cross price elasticities are positive, representing interfuel substitution.

9.1.2 Onshore Natural Gas Production Industry--Growth and Projections

This section discusses the historical production and price of natural gas. Natural gas production is projected for the years 1985, 1990 and 2000 and distributed in the categories of onshore, offshore, discoveries from existing fields and discoveries from new fields.

9.1.2.1 Historical Data. Marketed production of natural gas increased from 5.42 trillion cubic feet in 1949 to a peak of 22.65 trillion cubic feet in 1973. Increases in marketed production from 1949 through 1973 averaged 6.0 percent annually. In 1974 and 1975, marketed production decreased 4.6 percent and 6.9 percent, respectively. After 1976, marketed production declined slightly to 19.67 trillion cubic feet in 1979.

Total gross withdrawals of natural gas from both gas wells and oil wells generally follow the same trend as marketed production. However, the volume of natural gas withdrawn from oil wells has remained relatively constant at about three to five trillion cubic feet per year from 1949 to the present. Table 9-7 presents total natural gas production distributed between onshore and offshore production for the years 1949 through 1979.[2] Onshore production declined from 99.1 percent of the total in 1954 to 72.4 percent of the total in 1979. The difference between gross withdrawals and marketed production represents quantities from gas wells and oil wells that were either vented, flared or used for reservoir repressuring.[3] In 1980, there were approximately 175,000 producing gas wells in the United States. Although most natural gas is produced from natural gas wells, about 18 percent is produced from crude oil wells.

Table 9-7. NATURAL GAS GROSS WITHDRAWALS AND MARKETED ONSHORE AND OFFSHORE PRODUCTION

	Production in Trillion Cubic Feet						Percentage	
Year	From Gas Wells	From Oil Wells	Gross Withdrawals	Marketed Production[a]	Onshore Production	Offshore Production[c]	Onshore	Offshore
1949	4.99	2.56	7.55	5.42	NA	NA	NA	NA
1950	5.60	2.88	8.48	6.28	NA	NA	NA	NA
1951	6.48	3.21	9.69	7.46	NA	NA	NA	NA
1952	6.84	3.43	10.27	8.01	NA	NA	NA	NA
1953	7.10	3.55	10.65	8.40	NA	NA	NA	NA
1954	7.47	3.52	10.98	8.74	8.66	0.08	99.1	0.9
1955	7.84	3.88	11.72	9.41	9.28	0.13	98.6	1.4
1956	8.31	4.07	12.37	10.08	9.94	0.14	98.6	1.4
1957	8.72	4.19	12.91	10.68	10.51	0.17	98.4	1.6
1958	9.15	3.99	13.15	11.03	10.77	0.26	97.6	2.4
1959	10.10	4.13	14.23	12.05	11.70	0.35	97.1	2.9
1960	10.85	4.23	15.09	12.77	12.33	0.44	96.6	3.4
1961	11.20	4.27	15.46	13.25	12.77	0.48	96.4	3.6
1962	11.70	4.34	16.04	13.88	13.24	0.64	95.4	4.6
1963	12.61	4.37	16.97	14.75	13.99	0.76	94.8	5.2
1964	13.11	4.43	17.54	15.55	14.70	0.85	94.5	5.5
1965	13.52	4.44	17.96	16.04	15.10	0.94	94.1	5.9
1966	13.89	5.14	19.03	17.21	15.84	1.37	92.0	8.0
1967	15.35	4.91	20.25	18.17	16.33	1.84	89.9	10.1
1968	16.54	4.79	21.33	19.32	17.00	2.32	88.0	12.0
1969	17.49	5.19	22.68	20.70	17.86	2.84	86.3	13.7
1970	18.59	5.19	23.79	21.92	18.70	3.22	85.3	14.7
1971	18.93	5.16	24.09	22.49	18.74	3.75	83.2	16.8
1972	19.04	4.97	24.02	22.53	18.77	3.76	83.3	16.7
1973	19.37	4.70	24.07	22.65	18.67	3.98	82.4	17.6
1974	18.67	4.18	22.85	21.60	17.37	4.23	80.4	19.6
1975	17.38	3.72	21.10	20.11	15.85	4.26	78.8	21.2
1976	17.19	3.75	20.94	19.95	15.65	4.30	78.4	21.6
1977	17.42	3.68	21.10	20.03	15.49	4.54	77.3	22.7
1978	17.39	3.91	21.31	19.97	14.87	5.10	74.5	25.5
1979[b]	17.17	3.75	20.92	19.67	14.25	5.42	72.4	27.6

NA = Not Available.

[a] Marketed production is derived. It is gross withdrawals from producing reservoirs less gas used for reservoir representing and quantities vented and flared.

[b] Estimated, based on reported data through November.

Note: Sum of components may not equal total due to independent rounding. Beginning with 1965 data, all volumes are shown on a pressure base of 14.73 psia at 60°F. For prior years, the pressure base is 14.65 psia at 60°F.

Sources:

- 1949 through 1975, U.S. Department of the Interior, Bureau of Mines, Minerals Yearbook, "Natural Gas" chapter.
- 1976 through 1978, U.S. Department of Energy, Energy Information Administration, Natural Gas Production and Consumption, annual.

[c] Data from U.S. Department of the Interior, Geological Survey - Conservation Division, Outer Continental Shelf Statistics.

The nominal price of natural gas remained reasonably steady during the period from 1955 through 1973. Since 1973, the year of the Arab Oil Embargo, the price has consistently increased in real terms. Figure 9-1 shows selected natural gas prices for three categories for the period from 1955 through 1979. [4] In 1979, the price of natural gas at the wellhead was $1.13 per million Btu, $1.85 per million Btu at the city gate and $2.50 per million Btu delivered to ultimate customer. This consistent increase in the price coupled with the deregulation of the price of natural gas in almost all categories before the end of 1985 will boost the revenues and profitability margins for the industry. This will contribute to growth in capital availability potentially to be used for more drilling, deeper drilling and increased exploration and production of tight gas formations.

Since the Oil Embargo in 1973, the financial condition of the onshore crude oil and natural gas production industry has been improving steadily in both revenues and net profits. Composite financial data shown in Table 9-8 indicate increased revenues from $15,292 million in 1976 to $38,000 million in 1980. During the same period, net profits increased from $1,155 million to $1,925 million.

Composite net profit margins as a percent of sales however have declined from 7.6 percent in 1976 to 5.1 percent in 1980. This fact indicates that production costs have risen at a faster pace than prices. Also, total capital has grown at a slower pace than revenues and profits. Consequently, return on total assets and return on equity have improved. According to Value Line Investment Survey, the composite industry will continue to have a healthy financial future into the 1980's. It is projected in 1983-85 that the industry will have a composite net profit margin of 4.6 percent on annual revenues of approximately $70 billion in current dollars. The long term debt ratio is projected to be 45.5 percent. Total capital is projected to increase to $35,500 million in current dollars or 51 percent of revenues in 1983-85.

9.1.2.2 Five-Year Projections. In this subsection, projections for the number of new and modified and reconstructed gas processing facilities in the years 1983 through 1987 are developed. The form of the growth in terms of new facilities, modified facilities and reconstructed facilities

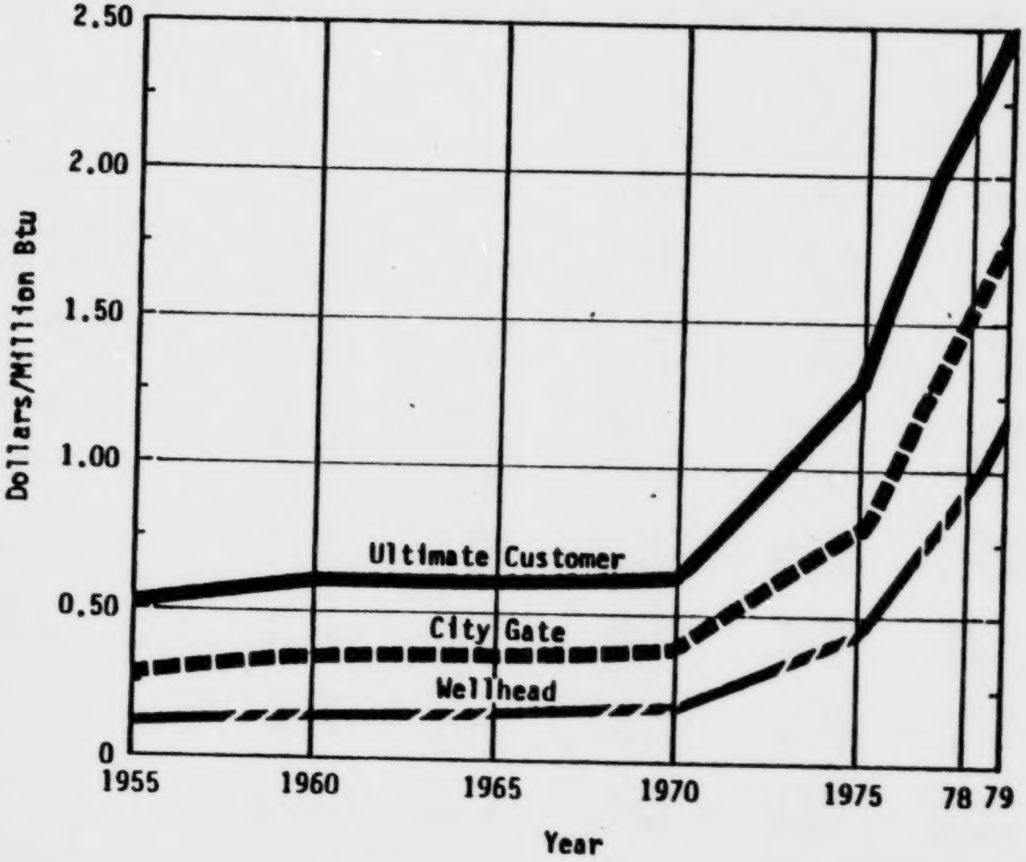

Figure 9-1. Selected natural gas prices — three categories for the period 1955-1979.[4]

Table 9-8. COMPOSITE FINANCIAL DATA FOR THE NATURAL GAS INDUSTRY 1976-1981 and 1983-1985 ESTIMATES (Current dollars)

Item	1976	1977	1978	1979	1980	1981	83-85E
Revenues ($mill)	15,292	19,430	22,463	30,357	38,000	46,000	70,000
Net Profit ($mill)	1,155	1,356	1,399	1,702	1,925	2,200	3,200
Income Tax Rate	44.4%	43.1%	43.9%	43.2%	44.0%	45.0%	47.0%
Net Profit Margin	7.6%	7.0%	6.2%	5.6%	5.1%	4.8%	4.6%
Long-term Debt Ratio	54.3%	50.8%	48.5%	48.0%	48.5%	47.0%	45.5%
Common Equity Ratio	41.0%	44.4%	46.8%	47.1%	48.0%	50.0%	53.0%
Total Capital ($mill)	19,538	20,207	20,611	22,236	23,750	26,000	35,500
Net Plant ($mill)	18,356	19,865	21,423	23,453	26,000	27,000	33,000
% Earned Total Capital	8.0%	8.8%	8.9%	9.8%	10.5%	10.5%	11.5%
% Earned Net Worth	12.9%	13.6%	13.2%	14.7%	15.5%	15.5%	16.5%
% Earned Comm. Equity	13.5%	14.2%	13.7%	15.4%	16.0%	16.0%	17.0%
% Retained to Comm. Equity	7.5%	8.0%	7.2%	8.9%	9.0%	9.0%	9.5%
% All Dividends to Net Profit	48%	47%	50%	45%	45%	45%	45%
Average Annual P/E Ratio	7.1	7.6	7.1	6.8	NA	NA	8.0
Average Annual Dividend Yield	6.3%	5.8%	6.6%	6.3%	NA	NA	6.0%
Fixed Charge Coverage	278%	281%	284%	287%	290%	295%	310%

E = Estimates
NA = Not available

Source: A. Bernhard & Company. "Natural Gas Industry." Value Line Investment Survey, July 18, 1980.

is discussed. The size distribution of new facilities is developed based upon industry's historical trend. Information on the projection of natural gas price is presented, and the effect of price deregulation on natural gas production is discussed.

Production of natural gas by conventional techniques has exceeded the rate of reserve additions in recent years. Consequently, conventional reserves are expected to continue declining and production from conventional reserves will decline as well. Annual production of conventional natural gas is expected to decline roughly 1.5 to 2.0 trillion cubic feet every five years through 1995. The production of associated and dissolved gas is expected to decline less rapidly than the production of nonassociated gas, due to higher price incentives for crude oil.

Table 9-9 presents the American Gas Association's (AGA) projected Lower-48 states conventional natural gas production for the period from 1980 through 2000.[5] In 1985, the production is projected to be 19.7 trillion cubic feet, decreasing to 17.7 trillion cubic feet in 1990. Natural gas produced through enhanced gas recovery (EGR) techniques is expected to increase rapidly and provide a significant portion of the production by 1995.

Production from new (past 1977) onshore discoveries according to AGA is projected to total 3.6 trillion cubic feet in 1985 and to increase consistently through 1990 when it will reach the maximum of 4.9 trillion cubic feet. An increasing percentage of total onshore production is projected to come from new discoveries.[5] Table 9-9 includes projected Lower-48 states onshore conventional natural gas production from new discoveries for the period from 1980 through 2000.[5] Figure 9-2 portrays the onshore natural gas production from new discoveries through the year 2000.

Natural gas supply projections are conducted by various oil and gas companies as well as government and independent study groups. Table 9-10 presents a comparison of 1990 projection forecasts presented by the Department of Energy (DOE), the American Gas Association (AGA), Exxon, Tenneco and other private study groups.[6] AGA's forecast of 16.3 quadrillion Btu per year is 8.4 percent lower than DOE's forecast of 17.8

Table 9-9. PROJECTED LOWER-48 STATES CONVENTIONAL NATURAL GAS PRODUCTION

Gas Source	Production, Trillion Cubic Feet 1980	1985	1990	1995	2000
Onshore					
Old Inter[a]	4.9	3.6	2.0	1.1	0.7
Old Intra[a]	3.6	2.4	1.3	0.7	0.4
Old Direct Sale	4.0	2.6	1.5	0.8	0.5
New	1.5	3.6	4.9	4.8	3.8
Offshore					
Old Inter[a,b]	5.6	4.1	1.4	0.7	nil
New Inter[c]	0.1	3.4	6.6	6.5	5.4
Total					
Old Inter	10.5	7.7	3.4	1.5	0.7
Old Intra	3.6	2.4	1.3	0.7	0.4
Old Direct Sale	4.0	2.6	1.5	0.8	0.5
New	1.6	7.0	11.5	11.3	9.2
TOTAL[d]	19.7	19.7	17.7	14.6	10.8

[a] Includes gas used as compressor fuel and net storage injections.

[b] Including new additions from pre-1977 leases.

[c] Post-1976 leases only.

[d] Totals may not add due to independent rounding.

Source: American Gas Association, Gas Supply and Statistics--Total Energy Resource Analysis Model (TERA) 80-1, Appendix A.

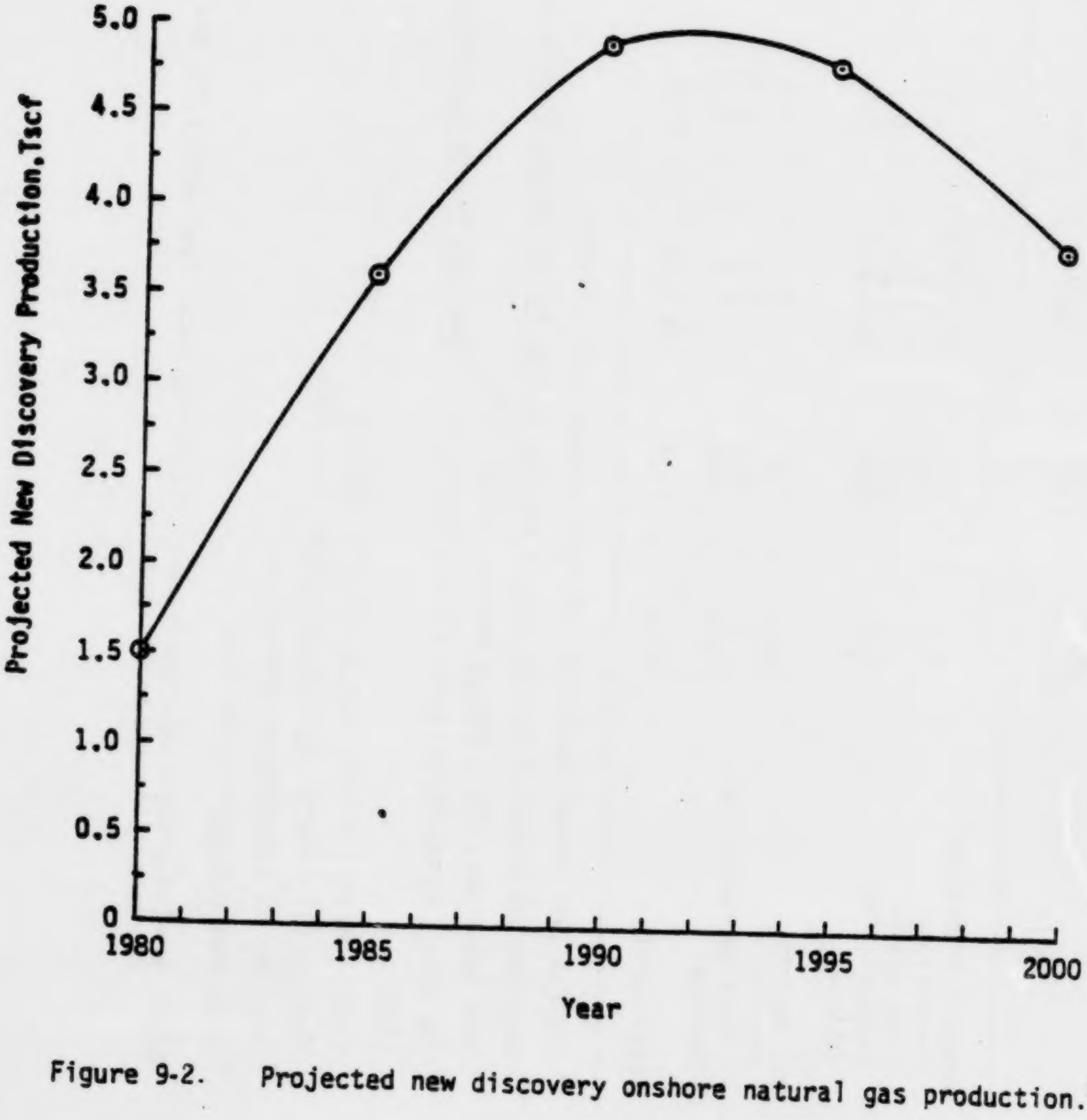

Figure 9-2. Projected new discovery onshore natural gas production.[5]

Table 9-10. PROJECTIONS OF NATURAL GAS SUPPLY: COMPARISON OF 1990 FORECASTS[6] (Quadrillion Btu)

Units	1978 Actual	1979 Projections for 1990					
		DOE/ EIA[a]	AGA[b]	DPP[c]	Pace[d]	Exxon[e]	Tenneco[f]
Domestic Production							
Conventional	19.5	17.8	15.3-17.3	16.9	16.1	14.9	14.8
North Alaska	f	0.9	1.6	0.4	1.0	f	1.0
Synthetic Gas	0.2	0.3	1.1	0.6	0.8	0.6-1.0	1.5
Subtotal	19.7	19.0	19.9-21.9	18.0	18.0	15.5-15.9	17.3
Net Imports							
Pipeline	0.9	0	2.1	2.0	1.4	1.8	2.0
Liquefied Natural Gas	g	0.8	2.0	1.0	0.8	0.8	3.1
Subtotal	0.9	0.8	4.2	3.1	2.2	2.7	5.1
Total Supply	20.6	19.8	24.1-26.1	21.0	20.2	18.2-18.6	22.4

[a] DOE/EIA 1979 Annual Report to Congress, middle range forecast.

[b] American Gas Association, The Future for Gas Energy in the United States, June 1979.

[c] Data Resources, Inc., Energy Review, Winter 1980.

[d] The Pace Company Consultants and Engineers, Inc., The Pace Energy and Petrochemical Outlook to 2000, October 1979.

[e] Exxon Company, U.S.A., Energy Outlook 1980-2101, December 1979.

[f] Tenneco Oil Company, Energy 1979-2000, June 1979.

[g] Included in conventional production.

[h] Less than 0.5 quadrillion Btu.

Note: Non-EIA projections converted from trillion cubic feet with 1,020 Btu per cubic foot. Numbers may not add to totals because of rounding.

quadrillion Btu per year, and Exxon's forecast of 14.9 quadrillion Btu is 16.3 percent lower than DOE's forecast. AGA's projections were used for the purposes of this study because their projections included estimates of new production. The other forecasters did not.

The natural gas processing industry is projected to add new plants needed to process new production. The number of new gas processing plants that are projected to begin operating between 1983 and 1987 are presented in Table 9-11. This table shows, for each year, the cumulative number of new plants that are expected to be in operation as a result of "new" natural gas production. For this analysis, "new" production is considered to be gas produced onshore after January 1, 1983 from any well located outside of a given radius and depth of a proven reserve and gas produced offshore from any tract leased after January 1, 1983. The figures listed under the "new production" column include the incremental new production for that particular year plus the gas produced from the new wells of the previous years, back to 1983. Therefore, the cumulative number of new gas plants expected to be in operation each of the five years was determined by dividing the projected annual new natural gas production by the average capacity of existing cryogenic gas plants. It is assumed that all new gas plants will employ the cryogenic process method.

In addition to new gas processing plants being constructed, it is estimated that approximately eight existing gas plants will be modified or reconstructed during each year during the period 1983-1987. This estimate approximates the number of expansions reported each year by Oil and Gas Journal's semi-annual report on plant expansions and equals one percent of the total number of gas plants in the United States.

Natural gas prices are projected by the Department of Energy to increase because of the Natural Gas Policy Act and phased deregulation of prices during the period from 1983 through 1987. By 1985, almost all categories of natural gas production will be deregulated. Very little new gas will be subject to controls; most old intrastate gas will be decontrolled and the quantity of old interstate gas that remains controlled will decline rapidly over time. Because of this phased deregulation, natural gas prices are projected to increase during the period from 1983

Table 9-11. ESTIMATED NUMBER OF NEW GAS PLANTS, 1983-1987

Year	New natural gas production[a] (trillion cubic feet)	Cumulative number of new gas plants[b]
1983	1.32	40
1984	2.62	80
1985	3.89	120
1986	4.99	150
1987	6.07	180

[a] "New" production is considered to be gas which is (1) produced from a new well beyond a specified distance from an old well; (2) produced from a reservoir from which gas was not produced in commercial quantities prior to January 1, 1983, or (3) produced from an offshore tract leased on or after January 1, 1983. These new production figures were developed based on American Gas Association's Total Energy Resource Analysis (TERA) Model 80-I, November 21, 1980. The figures reflect an average annual decline in production of 6.2 percent, and the source for this decline rate is the National Petroleum Council's U.S. Energy Outlook - Oil and Gas Availability, 1974.

[b] It is assumed that all new gas plants will be cryogenic gas plants, with an average capacity equivalent to the average capacity of existing cryogenic plants (90 MMcfd). Therefore, the number of new gas plants is developed by dividing the projected annual new production by the average capacity of existing cryogenic gas plants.

through 1987. In turn, deregulated prices are expected to boost exploration and production activities. The history and projections for natural gas prices are summarized in Table 9-12.[7]

9.2 ECONOMIC IMPACT ANALYSIS

This section presents the expected economic impacts of alternative emissions regulations limiting volatile organic compounds (VOC) emissions from natural gas/gasoline processing plants.

9.2.1 Economic Impact Assessment Methodology

The methodology for economic impact assessment of VOC emissions regulations on the onshore natural gas processing industry includes the following steps:

Step 1 - Analyze the absolute magnitude of additional pollution control costs in terms of before-tax annualized cost and after-tax annualized costs.

Step 2 - Determine percentage product price increases required for regulated plants to maintain constant profitability.

Step 3 - Analyze the regulated plants' ability to pass additional emissions control costs forward to consumers or backward to suppliers.

Step 4 - Determine the financial viability of regulated plants.

Step 5 - Analyze expected impacts of emissions regulations on plant closings, curtailment of expansion, industry output, industry prices, employment, wages, productivity, plant location, international trade, and possible balance of payments effects.

If it is determined in Step 1 and 2 that the emissions control costs are small in absolute and relative terms, then expected economic impacts on output, prices, employment, profitability, etc., will be small and further expenditure of resources for detailed impact analyses justifiably can be foregone. Such might be the case where annualized pollution control costs are much less than EPA's trigger criteria for regulatory analysis, i.e., $100 million additional (before tax) annualized cost or a price increase of 5 percent required for industry members to maintain pre-control levels of profitability.

Table 9-12. NATURAL GAS PRICES: HISTORY AND PROJECTIONS FOR 1965-1995
(1979 Dollars per Thousand Cubic Feet)

Price	History[a]			Projections[b]		
	1965	1973	1978	1985	1990	1995
Domestic Wellhead Prices						
Old Interstate	NA	NA	0.93	1.01	1.18	1.39
New Interstate	NA	NA	NA	4.48	4.04	4.59
Old Intrastate	NA	NA	NA	3.29	3.32	3.78
New Intrastate	NA	NA	NA	4.72	4.28	4.82
North Alaska	--	--	--	--	1.85	1.85
Average	0.36	0.35	1.02	3.26	3.42	4.17
Synthetic Gas Prices						
High-Btu Coal Gas	--	--	--	4.76	4.19	4.71
Medium-Btu Coal Gas	--	--	--	3.70	4.50	5.44
Imported Gas Prices						
Canadian Gas	NA	NA	2.41	6.21	6.92	8.51
Mexican Gas	NA	NA	NA	6.21	6.92	8.51
Liquefied Natural Gas	--	--	1.54	5.91	6.42	7.70
Delivered Prices						
Residential	2.34	2.04	2.77	5.41	5.74	6.45
Commercial	1.60	1.46	2.38	4.88	5.22	5.93
Raw Material	NA	NA	NA	4.28	4.48	5.21
Large boilers[c]	NA	NA	NA	5.24	4.54	5.26
Industrial, Other	0.78	0.77	1.61	4.34	4.51	5.22
Refineries	NA	NA	NA	4.55	4.43	5.13
Electric Utilities	0.89	0.63	1.72	4.74	4.42	--
Alternative Fuel Cost	--	--	--	6.23	6.94	8.29

[a] Source for historical data is Volume 2 of the EIA Annual Report to Congress, 1979, and the following EIA Energy Data Reports: Natural Gas Production and Consumption, 1978; United States Imports and Exports of Natural Gas, 1978; and, Natural and Synthetic Gas, 1978.

[c] Major fuel-burning installations.

Notes: NA = Not available.
-- = Not applicable.

[b] Source: DOE/EIA Annual Report to Congress, 1980, Vol. 13, pg. 90.

If it is determined in Steps 1 and 2 that the direct emissions control costs are significant in either absolute or relative cost to the industry, then the focus of the analysis turns toward analyzing the ability of regulated plants to pass additional costs forward to consumers or backward to suppliers. The analysis in Step 3 is explained in the context of the industry's structure, conduct and performance as described in Section 9.1. Specifically, the level of competition within the industry and the elasticity of demand to the regulated plants is important as well as the elasticity of aggregate product demand.

If it is determined that the industry is able to pass on all additional costs, then Step 4 can be omitted since the financial viability of regulated plants would not be jeopardized. Important impacts may occur in supplier or consumer sectors and these should be analyzed if expected price impacts are significant to these sectors. If, on the other hand, it is determined in Step 3 that the industry is unable to pass on all additional emissions control costs, then Step 4 is needed to determine the economic viability of regulated and impacted plants.

If needed, a net present value approach is used in Step 4 to determine the regulated plants' financial viability. Specifically, after-tax net annualized cost of emissions control is estimated and used to calculate required percentage price increases needed for regulated plants to maintain baseline net present values for each regulatory alternative. If the required price increase for some regulatory alternative exceeds the amount which can be successfully passed on or absorbed by the plant then it is determined that the plant is non-viable for that regulatory alternative.

Based on the findings in Steps 1 through 4 and the industry profile in Section 9.1, additional analyses of expected economic impacts are completed. Expected industry price and output impacts are estimated simultaneously. Then related impacts on employment, productivity, international trade, etc. are brought into focus in Step 5.

Before-tax annualized costs (BTAC) and after-tax annualized costs (ATAC) of emissions controls are computed in Step 1 using the following equations:

$$BTAC = I_o \, CRF + O\&M_o \tag{1}$$

$$ATAC = I_o \, CRF \, TAXF + (1-t) \, O\&M_o \tag{2}$$

where,

I_o = initial base year investment

OM_o = annual O&M cost less applicable by-product credits

$CRF = \frac{r(1+r)^n}{(1+r)^n - 1}$, the capital recovery factor

r = the real cost of capital

n = economic life of the asset, i.e. the capital recovery period (variable by asset)

$TAXF = 1 - itc - t \, PVDEP$

itc = investment tax credit rate

t = corporate income tax rate

$PVDEP$ = present value of annual depreciation factors per $1 of investment, i.e.

$$PVDEP = \sum_{y=1}^{Y} \frac{DEP_y}{(1+d)^y}$$

Y = length of the depreciation period, 3, 5, 10 or 15 years

d = nominal discount rate, and

DEP_y = annual depreciation factors based on the most advantageous depreciation methods for the firm, either (1) rapid amortization of pollution control investments or (2) accelerated cost recovery as allowed by the 1981 Economy Recovery Act.

Required real price increases needed by model gas processing plants to maintain baseline profitability (net present value) are computed according to Equation 3.

$$\text{Required real price increase } \underline{1/} = \frac{\text{ATAC}}{\text{Throughput (1-t)}} \qquad (3)$$

Inflation and the weighted nominal cost of capital are projected to be 8 and 10 percent, respectively. This inflation rate is consistent with recent estimates of large econometric models of the U.S. economy. 2/ Ten percent nominal weighted natural gas industry cost of capital was estimated using forecasted 1981-1985 composite natural gas industry stock price earnings ratios of 7 to 8, a 45 percent debt ratio, 47 percent marginal corporate income tax rates from Value Line Investment Survey, and 13 percent nominal pre-tax interest rate on new debt for domestic corporations based on Value Line Investment Survey estimates for 1981-1985.

9.2.2 Economic Impact of VOC Regulatory Alternatives - Natural Gas/Gasoline Processing Plants

Additional costs for natural gas processing plants to comply with VOC regulatory alternatives are expected to be small in both absolute and relative terms. Economic impacts on individual plants and the industry will be slight. Total additional before-tax annualized costs of controls in 1987, the fifth year of controls, are estimated to be as follows:

Regulatory alternatives, VOC	Total additional before-tax annualized cost, 1987 (thousand 1980 dollars)
I	0
II	220.5
III	652.9
IV	8,080.2

1/ The assumption $\Delta NPV = 0$ requires that $(1-t)\ \Delta P\ Q - ATAC = 0$; therefore, $\Delta P = ATAC/(1-t)Q$. P = the real price increase required to amortize at the cost of capital the additional pollution control investment and operating costs over constant throughput Q.

2/ Data Resources, Inc. Trendlong 2005 Forecasts. September, 1980.

These estimates are derived at the bottom of Table 9-13 which displays aggregate or total before-tax annualized costs of regulatory alternatives II, III, and IV by year. The projected number of new gas plants during the period 1983-1987 is 180 mid-size plants. The total before-tax annualized cost for these new plants in 1987, the fifth year of the regulation, is $361,800 for regulatory alternative II, $585,000 for regulatory alternative III and $5,482,800 for regulatory alternative IV.

The projected number of modified and reconstructed plants during the period 1983-1987 is 10 small, 15 mid-size and 15 large plants. The total before-tax annualized cost for these modified and reconstructed plants in 1987 is -$141,300 for regulatory alternative II, $67,900 for regulatory alternative III and nearly $2.6 million for regulatory alternative IV. The combined total of new and modified and reconstructed plants constructed during the period 1983-1987 is 10 small plants, 195 mid-size plants, and 15 large plants. Total before-tax annualized costs for these plants in 1987 is estimated to be $220,500 for regulatory alternative II, $652,900 for regulatory alternative III and nearly $8.1 million for regulatory alternative IV.

Before-tax net annualized costs for individual model gas plants and regulatory alternatives I through IV are shown in Table 9-14. The new model plant, producing 90 million cubic feet per day, has before-tax annualized costs for regulatory alternatives II, III, IV totalling $2,010, $3,250 and $30,460 respectively. The smallest modified and reconstructed model plant has before-tax net annualized costs of $3,060, $4,840 and $17,280 for alternatives II, III and IV, respectively. For the modified and reconstructed model plant B costs are $2,010, $3,250, and $40,080 while model plant C has costs of -$13,470, -$1,950 and $121,550 for regulatory alternatives II, III and IV, respectively. Negative before-tax net annualized costs stem from situations where recovery credits outweigh the annualized investment and operating costs for emissions control.

After-tax net annualized costs of regulatory alternatives are shown in Table 9-15. For the new model plant, the after-tax net annualized cost for alternatives II, III and IV are $2,390, $2,590 and $16,660, respectively.

Table 9-13. ONSHORE NATURAL GAS PROCESSING, TOTAL AND CUMULATIVE BEFORE-TAX NET ANNUALIZED COST OF VOC REGULATORY ALTERNATIVES 1983-1987

Category of Facility	Year	Projected Cumulative Number of Gas Plants a/			Regulatory Alternative		
		A	B	C	II	III	IV
					-------Thousands of 1980 Dollars------		
New							
	1983	0	40	0	80.4	130.0	1,218.4
	1984	0	80	0	160.8	260.0	2,436.8
	1985	0	120	0	241.2	390.0	3,655.2
	1986	0	150	0	301.5	487.5	4,569.0
	1987	0	180	0	361.8	585.0	5,482.8
Modified/Reconstructed							
	1983	2	3	3	-28.3	13.6	519.5
	1984	4	6	6	-56.5	27.2	1,039.0
	1985	6	9	9	-84.8	40.7	1,558.5
	1986	8	12	12	-113.0	54.3	2,077.9
	1987	10	15	15	-141.3	67.9	2,597.4
Total New, Modified & Reconstructed							
	1983	2	43	3	52.1	143.6	1,737.9
	1984	4	86	6	104.3	287.2	3,475.8
	1985	6	129	9	156.4	430.7	5,213.7
	1986	8	162	12	188.5	541.8	6,646.9
	1987	10	195	15	220.5	652.9	8,080.2

a/ Plants A, B and C ave. 10, 30 and 100 vessels, respectively.

Table 9-14. ONSHORE NATURAL GAS PROCESSING MODEL PLANTS' BEFORE-TAX NET ANNUALIZED COST OF VOC REGULATORY ALTERNATIVES PER PLANT

Model plant	Size		Regulatory alternative			
	No. vessels	MMcfd	I Baseline control level	II	III	IV
			Thousands of 1980 dollars			
New	30	90	0	2.01	3.25	30.46
Modified and Reconstructed						
A	10	30	0	3.06	4.84	17.28
B	30	90	0	2.01	3.25	40.08
C	100	250	0	-13.47	-1.95	121.55

Table 9-15. ONSHORE NATURAL GAS PROCESSING MODEL PLANTS' AFTER-TAX NET ANNUALIZED COST OF VOC REGULATORY ALTERNATIVES PER PLANT

Model plant	Size		Regulatory alternative			
	No. vessels	MMcfd	I Baseline control level	II	III	IV
			----------------Thousands of 1980 dollars----------------			
New	30	90	0	2.39	2.59	16.66
Modified and Reconstructed						
A	10	30	0	2.06	2.88	9.32
B	30	90	0	2.39	2.59	21.68
C	100	250	0	-2.86	1.88	65.82

For modified and reconstructed model plant A, these costs are $2,060, $2,880, and $9,320, respectively; $2,390, $2,590, and $21,680, respectively, for model plant B; and -$2,860, $1,880 and $65,820 for model plant C.

Required price increases for affected gas plants to maintain baseline profitability (net present value) are very small as estimated below. For purposes of this order of magnitude calculation, gas throughput was assumed to be 30, 90, and 250 MMcfd for plants A, B, and C, respectively. Gas throughput for new cryogenic plants was assumed to be 90 MMcfd as explained in Table 9-11 footnote b.

Required price increases for VOC Regulatory Alternatives, 1980 $/Mcf

Regulatory alternative	New	Modified and Reconstructed		
	Plant B (90 MMcfd)	Plant A (30 MMcfd)	Plant B (90 MMcfd)	Plant C (250 MMcfd)
II	.00020	.00052	.00020	-.00009
III	.00022	.00072	.00022	.00006
IV	.00140	.00234	.00182	.00199

Given the inelasticity of retail demand for natural gas and gas liquids products, it is expected that gas processors will pass a large portion, if not all, of the incremental emissions control costs forward to pipelines, gas utilities and eventually to the ultimate consumers of natural gas and natural gas liquids. The price impacts will be slight relative to current product prices, less than 0.5 percent, regardless of regulatory alternative. No plant closures or curtailments are expected due to the VOC regulatory alternatives analyzed. Effects on industry profitability, output, growth, employment, productivity, and international trade will be negligible or zero due to the VOC regulatory alternatives analyzed.

This concludes the analysis of direct economic impacts of VOC regulatory alternatives on the Natural Gas Processing Industry. Control costs for VOC regulatory alternatives and associated economic impacts are expected to be negligible for individual plants and particularly for the composite natural gas processing industry.

9.3 POTENTIAL SOCIOECONOMIC AND INFLATIONARY IMPACTS

This section discusses the potential social disruption and inflationary impacts associated with the VOC regulatory alternatives.

Data presented in Section 9.2 above indicated that additional costs for control of VOC emissions from natural gas processing plants are expected to be small on an absolute and relative basis for all four regulatory alternatives considered. No impact is expected on plant location or structure of the natural gas processing industry. No job losses are expected.

Additional costs for VOC emissions controls on new, remodeled and reconstructed gas plants are not expected to have significant inflationary impacts because the annualized control costs per unit of production are small, i.e., less than 0.5 percent of sales for all model plants and regulatory alternatives. It is expected, however, that gas processors will succeed in passing a large share of the added costs forward into product markets for natural gas liquids. The direct effect on price will be negligible, especially when compared to total industry sales, including existing (exempt) plants. No productivity, plant location, or balance of payments effects are expected due to any of the VOC regulatory alternatives.

9.4 REFERENCES FOR CHAPTER 9

1. Oil & Gas Journal, January 28, 1980, p. 81. Docket Reference Number A-80-20-B (VOC) II-I-39.*

2. U.S. Deparment of Energy, Energy Information Administration. Annual Report to Congress-1979. Volume Two (of Three): Data, Docket Reference Number A-80-20-B (VOC) II-I-36,* and, U.S. Department of the Interior, U.S. Geological Survey-Conservation Division, Outer Continental Shelf Statistics, June 1980. Docket Reference Number A-80-20-B (VOC) II-I-40.*

3. U.S. Department of Energy, Energy Information Administration. Annual Report to Congress-1979. Volume Two (of Three): Data. Docket Reference Number A-80-20-B (VOC) II-I-36.*

4. American Gas Association, Department of Statistics, Gas Facts - 1979 Data. Docket Reference Number A-80-20-B (VOC) II-I-38.*

5. American Gas Association, Gas Supply and Statistics - Total Energy Resource Analysis Model (TERA) 80-1, Appendix A, Figure A-2, p. 21. Docket Reference Number A-80-20-B (VOC) II-I-41.*

6. U.S. Department of Energy, Energy Information Administration. Annual Report to Congress-1979. Volume Three (of Three): Projects. Docket Reference Number A-80-20-B (VOC) II-I-37.*

7. U.S. Department of Energy, Energy Information Administration. Annual Report to Congress-1979. Volume Three (of Three): Projections. Docket Reference Number A-80-20-B (VOC) II-I-37.*

*References can be located in Docket Number A-80-20-B at U.S. Environmental Protection Agency Library, Waterside Mall, Washington, D.C.

APPENDIX A — EVOLUTION OF THE BACKGROUND INFORMATION DOCUMENT

APPENDIX A - Evolution of the Background Information Document

Date	Nature of Action
November 30, 1979	Meeting to discuss onshore production and to solicit the aid of API in gathering field data.
December 7, 1979	Introductory meeting with API.
December 18, 1979	Visit to Exxon Company, U.S.A., Blackjack Creek facility, Jay Field, Florida to gain familiarity with process equipment and operating conditions.
December 19, 1979	Visit to Phillips Petroleum, Chatham facility, Chatham, Mississippi, to gain familarity with process equipment and operating conditions.
January 1980	Plant visits to various tank battery sites in the West Texas oil and gas field to gain knowledge of processing equipment.
March 19, 1980	Source Category Survey Report.
July 14, 1980	Visit to Exxon Company tank battery in Kingsville, Texas, to gain familarity with gas and oil production processes and facilities.
July 16, 1980	Visit to Phillips Petroleum Company, Roosevelt County, New Mexico, to acquire familiarity with gas and oil product in processes and facilities.
July 18, 1980	Visit to Shell Oil Company Stateline Production Unit in Sidney, Montana, to acquire familiarity with gas and oil production.

July 21 & 22, 1980	Meeting with API concerning NSPS development for the onshore production industry.
July 24, 1980	Visit to Phillips Petroleum Company, Canadian County, Oklahoma, to gain information on gas processing facilities.
October 6-9, 1980	Emission source testing at Houston Oil and Minerals, Smith Point gas plant, Chambers County, Texas.
October 14-16, 1980	Emission source testing at Amoco Production Company, Hastings gas plant, Brazoria County, Texas.
February 9-27, 1981	Emission source testing at Texas, Inc., Paradis gas plant, Paradis, Louisiana.
March 2-13, 1981	Emission source testing at Gulf Oil Company, Venice Plant, Venice, Louisiana.
March 1981	Preliminary draft CTG document, Control of Volatile Organic Compound Equipment leaks from National gas/gasoline processing plants.
April 29 & 30, 1981	Meeting of the National Air Pollution Control Techniques Advisory Committee to review the gas/gasoline processing plants standard.
April 1981	Model plant package mailed to industry representatives for comment.
May 1, 1981	Meeting with API concerning Model plants.

September 1981	Drafts of Chapters 3 through 6 sent out for industry review and comments.
December 1981	Draft CTG Document, Control of Volatile Organic Compound Equipment Leaks from Natural Gas/Gasoline Processing Plants.
January 28, 1982	Meeting with API concerning fugitive VOC emission factor development for gas plants.
July 21, 1982	NAPCTAC Meeting
August 18, 1982	Meeting with industry representatives to discuss comments on the draft NSPS for natural gas processing plants.
November 11, 1982	Visits to Phillips Petroleum Co., Alvin, Texas, plant and Amoco Production Co., Old Ocean, Texas, Plant.
November 12, 1982	Visits to Texaco U.S.A.; Blessing, Texas, Plant and Seagull Products Co., Pelacious Texas, Plant.
January 25, 1983	Meeting with Union Texas Petroleum Co. to discuss comments on the draft NSPS for natural gas processing plants.

APPENDIX B — INDEX TO ENVIRONMENTAL IMPACT CONSIDERATIONS

Table B-1. INDEX TO ENVIRONMENTAL IMPACT CONSIDERATIONS

Agency Guidelines for Preparing Regulatory Action Environmental Impact Statements (39 FR 37419)	Location Within the Background Information Document (BID)
1. Background, description, and purpose of the regulatory alternatives and the statutory authority.	The regulatory alternatives from which standards will be chosen are summarized in Chapter 1, Section 1.1, as is the statutory authority for proposing standards.
The relationship to other actions and proposals significantly affected by the regulatory alternatives.	To the extent possible, other regulations that apply to the affected industries are detailed in Chapter 8, Section 8.2 and are considered in the economic impact study in Chapter 9.
Industry affected by the regulatory alternatives.	The industry and emission sources within the industry affected by the regulatory alternatives are listed in Chapter 3.
Specific sources affected by the regulatory alternatives.	The specific sources affected by the regulatory alternatives are summarized in Chapter 3, Section 3.2.
Applicable control techniques.	A discussion of available emission control techniques is presented in Chapter 4, Sections 4.2 and 4.3.
2. Alternatives to the action.	The various categories of alternatives to the actions which were considered are listed below. a. Alternative regulatory approaches. The alternative approaches for regulating VOC emissions under Section 111 of the Clean Air Act are outlined in Chapter 6. b. Alternative control techniques. The alternative control techniques that could be utilized by the regulatory alternatives are outlined in Chapter 4.

(continued)

Table B-1. CONTINUED

Agency Guidelines for Preparing Regulatory Action Environmental Impact Statements (39 FR 37419)	Location Within the Background Information Document (BID)
Agency's comparative evaluation of the beneficial and adverse environmental, health, social, and economic effects of each reasonable alternative.	a. A discussion of the Agency's comparative evaluation of the various alternative regulatory approaches for VOC emissions from onshore natural gas production facilities can be found in Chapter 6, Section 6.3.
	b. A summary of the beneficial and adverse environmental effects of the regulatory alternatives can be found in Chapter 7. A detailed description of the economic impacts of each alternative control level, including the capital and annual costs to the industry, can be found in Chapter 8. The socioeconomic impacts of the regulatory alternatives can be found in Chapter 9.
3. Environmental impact of the regulatory alternatives.	
a. Primary impact.	
Primary impacts are those that can be attributed directly to the action, such as reduced levels of specific pollutants brought about by a new standard and the physical changes that occur in the various media with this reduction.	The primary air impacts of the alternative control levels are quantified in Chapter 7, Section 7.2.

(continued)

Table B-1. CONCLUDED

Agency Guidelines for Preparing Regulatory Action Environmental Impact Statements (39 FR 37419)	Location Within the Background Information Document (BID)
b. Secondary impact.	
Secondary impacts are indirect or induced impacts. For example, mandatory reduction of specific pollutants brought about by a new standard could result in the adoption of control technology that exacerbates another pollution problem and would be a secondary impact.	Other environmental impacts (i.e., solid waste, water quality) of the individual controls that can be used to meet the regulatory alternatives are identified qualitatively in Chapter 7, Sections 7.3, and 7.4. The energy impacts of the alternative control levels are quantified in Chapter 7, Section 7.5.
4. Other considerations.	
a. Adverse impacts which cannot be avoided should a regulatory alternative be implemented.	A summary of the potential adverse environmental impacts of the regulatory alternatives and a discussion of the significance of each impact can be found in Chapter 7.
b. Irreversible and irretrievable commitments of resources that would be involved with the regulatory alternatives, should one be implemented.	A discussion of irreversible and irretrievable committment of resources is in Section 7.6.1.

APPENDIX C. EMISSION SOURCE TEST DATA

APPENDIX C. EMISSION SOURCE TEST DATA

Fugitive emission test data have been collected at six natural gas/gasoline processing plants (see Table C-1) by EPA and industry. Two gas plants were tested under contract to the American Petroleum Institute (API), and four gas plants were tested under contract to EPA. All six gas plants were screened for fugitive emissions using either portable hydrocarbon detection instruments, soap solution, or both. Instrument screening (using EPA's proposed Method 21, described in Appendix D) was performed at all four of the EPA-tested plants (Plants 3, 4, 5, and 6). The instruments were calibrated with methane. Soap screening (using the method described in Reference 1) was performed at the two API-tested plants and at three of the EPA-tested plants. Selected components were measured for mass emissions at both of the API-tested plants (Plants 1 and 2) and at two of the EPA-tested plants (Plants 5 and 6). These mass emission measurements were used in development of emission factors for gas plant fugitives, which are presented in Table 3-1. A study of maintenance effectiveness at production field tank batteries was also performed by API. These data are discussed in Section C.2.

C.1 PLANT DESCRIPTION AND TEST RESULTS

One API-tested gas plant was of the refrigerated absorption type, and the other was a cryogenic plant. Descriptions and schematics of the plants are provided in Reference 1. Of the four EPA-tested plants, the first tested was a solid bed adsorption type (Reference 2). Natural gas liquids are removed by adsorption onto silica gel, then stripped from the bed with hot regeneration gas and condensed out for sales. There were three adsorption units, of which only one was operating. This unit had a capacity of 60 MMSCFD (million standard cubic feet per day), and was operating between 33 and 55 MMSCFD during the testing period. The second unit was shut down and depressurized, and therefore not tested.

Table C-1. GAS PLANTS TESTED FOR FUGITIVE EMISSIONS[a]

Plant No.	Data collection sponsor	Plant process type	Principal screening method(s) used
1	API	Refrigerated Absorption	Soaping
2	API	Cryogenic	Soaping
3	EPA	Adsorption	Instrument, Soaping
4	EPA	Cryogenic	Instrument, Soaping
5	EPA	Refrigerated Absorption	Instrument, Soaping
6	EPA	Refrigerated Absorption	Instrument[b]

[a] Reference 6.

[b] Less than 50 components were soap screened at plant No. 6.

The third unit was also not operating, but it was under natural gas pressure and was tested.

The second EPA-tested plant was of the cryogenic type (Reference 3). Feed gas to the plant is compressed and then chilled. Natural gas liquids are condensed out and split into two streams: ethane/propane and butane-plus. The cryogenic plant was operating at its rated capacity of 30 MMSCFD.

The third EPA-tested plant was of the refrigerated absorption type (Reference 4). There were three absorption systems for removal of natural gas liquids. The liquids were combined and sent to a single fractionation train. The fractionation train separated the liquids into ethane, propane, iso-butane, butane, and debutanized natural gasoline. Testing was performed on the fractionation train and on the largest absorption system. The absorption system that was tested was operating at 450 MMSCFD, near its capacity of 500 MMSCFD.

The fourth EPA-tested plant was also of the refrigerated absorption type (Reference 5). There were two parallel absorption trains, and one fractionation train. Natural gas liquids were fractionated into ethane/propane, propane, iso-butane, butane, and debutanized natural gasoline streams. The plant was operating at approximately 450 MMSCFD, about half of its rated capacity of 800 MMSCFD.

A summary of the instrument screening data collected at the four EPA-tested plants is presented in Table C-2. A summary of the soap screening data collected at the two API-tested plants and at all of the EPA-tested plants is presented in Table C-3. (Only a very small amount of soap screening data were collected at Plant 6). The instrument screening data are tabulated for each plant, showing the number of each type of component tested and the percent emitting. The soap screening data are not tabulated for each plant but are instead summarized by soap score. A complete tabulation of the soap screening data by plant and by soap score is provided in Reference 6.

C.2 INDUSTRY VALVE MAINTENANCE STUDY

The API study that developed the gas plant data presented in Section C.1 also included a study of maintenance. Gate valves in gas and condensate service in oil and gas production field tank batteries were studied.

The sources were monitored with soap scoring at intervals over a 9-month period. Maintenance was performed on a portion of the valves studied. The results of an analysis of this data show that monthly leak occurrence was 1.3 percent, monthly leak recurrence was 1.6 percent, and leak repair effectiveness was 100 percent.[7] These results compare favorably with the 1.3 percent monthly leak occurrence and recurrence and 90 percent repair effectiveness used to analyze leak detection and repair control effectiveness in Chapter 4 and 7. The industry study results were not specifically used here, however, because (1) the data were gathered in tank batteries which, based on API data, appear to have different leak characteristics, (2) very few valves were studied (25 total data points), and (3) a soapscore value of 3 was used to define a leak rather than a meter reading of 10,000 ppm.

Table C-2. INSTRUMENT SCREENING DATA FOR EPA-TESTED GAS PLANTS[a]

	Valves		Relief valves		Open-ended lines		Compressor seals		Pump seals		Flanges and connections	
Plant No.	No. Tested	Percent ≥10,000 ppmv	No. Tested	Percent ≥10,000 ppmv	No. Tested	Percent ≥10,000 ppmv	No. Tested	Percent ≥10,000 ppmv	No. Tested	Percent ≥10,000 ppmv	No. Tested	Percent ≥10,000 ppmv
3	331	23.6	10	90.0	45	15.6	0	0.0	1	0.0	223	5.4
4	506	16.8	7	14.3	65	18.5	4	100	9	44.4	281	2.1
5	1,804	12.1	60	5.0	472	11.7	30	46.7	51	33.3	768	3.6
6	1,038	21.5	3	33.3	139	8.6	2	50.0	40	22.5	506	2.0
Total	3,679	16.4	80	17.5	721	11.9	36	52.8	101	29.7	1,778	3.1

[a] Reference 6.

Table C-3. SOAP SCREENING DATA FOR API-TESTED AND EPA-TESTED GAS PLANTS[a]

Soap Score	Valves		Relief valves		Open-ended lines		Compressor seals		Pump seals		Flanges and connections	
	Number	% of Total	Number	% of Total	Number	% of Total	Number	% of Total	Number	% of Total	Number	% of Total
0	4,483	75.1	123	91.8	945	79.2	8	28.6	14	77.8		
1	322	5.4	4	3.0	63	5.3	1	3.6	0	0.0	17,982	92.7
2	468	7.8	2	1.5	83	7.0	2	7.1	1	5.6	706	3.6
3	426	7.1	2	1.5	59	4.9	7	25.0	0	0.0	454	2.3
4	274	4.6	3	2.2	43	3.6	10	35.7	3	16.7	190	1.0
Total	5,973		134		1,193		28		18		65	0.3
											19,397	

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[a] Includes data from two API-tested plants and four EPA-tested plants. Reference 6.

C.3 REFERENCES FOR APPENDIX C

1. Eaton, W. S., et al., Fugitive Hydrocarbon Emissions from Petroleum Production Operations. API Publication No. 4322. March 1980. Docket Reference Number II-I-20, II-I-21.*

2. Harris, G. E. Fugitive VOC Testing at Houston Oil and Minerals Smith Point Plant. U.S. EPA, ESED/EMB Report No. 80-OSP-1. October 1981. Docket Reference Number II-A-13.*

3. Harris, G. E. Fugitive VOC Testing at the Amoco Hastings Gas Plant. U.S. EPA, ESED/EMB Report No. 80-OSP-2. July 1981. Docket Reference Number II-A-12.*

4. Harris, G. E. Fugitive VOC Testing at the Texaco Paradis Gas Plant, Volume I and II. U.S. EPA, ESED/EMB Report No. 81-OSP-7. July 1981. Docket Reference Numbers II-A-17, II-A-18.*

5. Harris, G. E. Fugitive Test Report at the Gulf Venice Gas Plant, Volume I and II. U.S. EPA, ESED/EMB Report No. 80-OSP-8. September 1981. Docket Reference Number II-A-14, II-A-15.*

6. DuBose, D. A., J. I. Steinmetz, and G. E. Harris. Emission Factors and Leak Frequencies for Fittings in Gas Plant. Final Report. U.S. EPA, ESED/EMB Report No. 80-FOL-1. July 1982. Docket Reference Number II-A-19.*

7. Memorandum, Hustvedt, K.C., EPA to Durham, J.F., EPA "API/Rockwell Maintenance Data". December 9, 1982. Docket Reference Number II-B-22.*

*References can be located in Docket Number A-80-20-B at the U.S. Environmental Protection Agency Library, Waterside Mall, Washington, D.C.

APPENDIX D

EMISSION MEASUREMENT AND CONTINUOUS MONITORING

APPENDIX D. EMISSION MEASUREMENT AND CONTINUOUS MONITORING

D.1 EMISSION MEASUREMENT METHODS

D.1.1 General Background

A test method was not available when EPA began the development of control technique guidelines, new source performance standards, and hazardous pollutant standards for fugitive volatile organic compounds from industrial categories such as petroleum refineries, synthetic organic chemical manufacturing, and other types of processes that handle organic materials.

During development and selection of a test method, EPA reviewed the available methods for measurement of fugitive leaks with emphasis on procedures that would provide data on emission rates from each source. To measure emission rates, each individual piece of equipment must be enclosed in a temporary cover for emission containment. After containment, the leak rate can be determined using concentration change and flow measurements. This procedure has been used in several studies[1,2] and has been demonstrated to be a feasible method for research purposes. It was not selected for this study because direct measurement of emission rates from leaks is a time consuming and expensive procedure, and is not feasible or practical for routine testing.

Procedures that yield qualitative or semiquantitative indications of leak rates were then reviewed. There are essentially two alternatives: leak detection by spraying each component leak source with a soap solution and observing whether or not bubbles were formed; and, the use of a portable analyzer to survey for the presence of increased organic compound concentration in the vicinity of a leak source. Visual, audible, or olefactory inspections are too subjective to be used as indicators of leakage in these applications. The use of a portable analyzer was selected as a basis for the method because it would have been difficult to establish an enforceable leak definition based on a subjectve parameter such as bubble formation rates. Also, the temperature of the component, physical configuration, and relative movement of parts often interfere with bubble formation.

Once the basic detection principal was selected, it was then necessary to define the procedures for use of the portable analyzer. Prior to performance of the first field test, a procedure was reported that conducted surveys at a distance of 5 cm from the components.[3] This information was used to formulate the test plant for initial testing.[4] In addition, measurements were made at distances of 25 cm and 40 cm on three perpendicular lines around individual sources. Of the three distances, the most repeatable indicator of the presence of a leak was a measurement of 5 cm, with a leak definition concentration of 100 or 1,000 ppmv. The localized meteorological conditions affected dispersion significantly at greater distances. Also, it was more difficult to define a leak at greater distances because of the small changes from ambient concentrations observed. Surveys were conducted at 5 cm from the source during the next three facility tests.

The procedure was distributed for comment in a draft control techniques guideline document.[5] Many commenters felt that a measurement distance of 5 cm could not be accurately repeated during screening tests. Since the concentration profile is rapidly changing between 0 and 10 cm from the source, a small variance from 5 cm could significantly affect the concentration measurement. In response to these comments, the procedures were changed so that measurements were made at the surface of the interface, or essentially 0 cm. This change required that the leak definition be increased. Additional testing at two refineries and three chemical plants was performed by measuring volatile organic concentrations at the interface surface.

A complication that this change introduces is that a small mass emission rate leak ("pin-hole leak") can be totally captured by the instrument and a high concentration result will be obtained. This has occurred occasionally in EPA tests, and a solution to this problem has not been found.

The calibration basis for the analyzer was evaluated. It was recognized that there are a number of potential vapor stream components and compositions that can be expected. Since all analyzer types do not respond equally to different compounds, it was necessary to establish a reference calibration material. Based on the expected compounds and the limited information available on instrument response factors, hexane was chosen as the reference calibration gas for EPA test programs. At the 5 cm measurement distance, calibrations were conducted at approximately 100 or 1,000 ppmv levels. After the measurement distance was changed, calibrations at 10,000 ppmv levels were required. Commenters pointed out that hexane standards at this concentration were not readily available commercially. Consequently, modifications were incorporated to allow alternate standard preparation procedures or alternate calibration gases in the test method recommended in the Control Techniques Guideline Document for Petroleum Refinery Fugitive Emissions.

Since that time, studies have been completed that measured the response factors for several instrument types.[6,7,8] The results of these studies show that the response factors for methane and hexane are similar enough for the purposes of this method to be used interchangeably. Therefore, in later NSPS, the calibration materials were hexane or methane.

The alternative of specifying a different calibration material for each type stream and normalization factors for each instrument type was not intensively investigated. There are at least four instrument types available that might be used in this procedure, and there are a large number of potential stream compositions possible. The amount of prior knowledge necessary to develop and subsequently use such factors would make the interpretation of results prohibitively complicated. Additionally, based on EPA test results, the measured frequency of leak occurrence in a process unit was not significantly different when the leak definition was based on meter reading using a reference material and when response factors were used to correct meter readings to actual concentrations for comparison to the leak definition.

An alternative approach to leak detection was evaluated by EPA during field testing.[9,10] The approach used was an area survey, or walkthrough, using a portable analyzer. The unit area was surveyed by walking through the unit, positioning the instrument probe within 1 meter of all valves and pumps. The concentration readings were recorded on a portable strip chart recorder. After completion of the walkthrough, the local wind conditions were used with the chart data to locate the approximate source of any increased ambient concentrations. This procedure was found to yield mixed results. In some cases, the majority of leaks located by individual component testing could be located by walkthrough surveys. In other tests, prevailing dispersion conditions and local elevated ambient concentrations complicated or prevented the interpretation of the results. Additionally, it was not possible to develop a general criteria specifying how much of an ambient increase at a distance of 1 meter is indicative of a 10,000 ppm concentration at the leak source. Because of the potential variability in results from site to site, routine walkthrough surveys were not selected as a reference or alternate test procedure.

D.1.2 Emission Testing Experience

During the data collection phase of this project, tests were conducted at four natural gas liquids facilities. Each unit was surveyed using Method 21 and, for portions of two plants, comparative screening using a soap scoring technique was performed. The purpose of this comparison was to determine if leak detection by the two methods could be incorporated into one data set for emission factor calculation. The result of this comparison was a general correlation between soap scoring and Method 21 and the combination of the two data sets for emission factor development.[11] Because soap scoring could not be used in all cases and because soap scoring requires subjective observations while an objective concentration measurement procedure is available, this alternate procedure was not included as a part of the reference test procedure. However, soaping is being allowed as a preliminary screening technique. For sources where soaping is possible, soap would be applied to the potential leak surfaces and if no bubbles are observed, the source is presumed not to be leaking.

In addition, source enclosure with measurement was performed at two plants to develop additional emission rate data. The test procedures and results are described in Reference 11.

The calibration species used in this study was methane. Flame ionization type analyzers were used for screening. The analyzers were tested and could achieve the performance requirements of Method 21.

D.2 CONTINUOUS MONITORING SYSTEMS AND DEVICES

Since the leak determination procedure is not a direct emission measurement technique, there are no continuous monitoring approaches that are directly applicable. Continual surveillance is achieved by repeated monitoring or screening of affected potential leak sources. A continuous monitoring system or device could serve as an indicator that a leak has developed between inspection intervals. The EPA performed a limited evaluation of fixed-point monitoring systems for their effectiveness in leak detection.[8,12,13] The systems consisted of both remote sensing devices with a central readout and a central analyzer system (gas chromatograph) with remotely collected samples. The results of these tests indicated that fixed point systems were not capable of sensing all leaks that were found by individual component testing. This is to be expected since these systems are significantly affected by local dispersion conditions and would require either many individual point locations, or very low detection sensitivities in order to achieve similar results to those obtained using an individual component survey.

It is recommended that fixed-point monitoring systems not be required since general specifications cannot be formulated to assure equivalent results, and each installation would have to be evaluated individually.

D.3 PERFORMANCE TEST METHOD

The recommended fugitive emission detection procedure is Reference Method 21. This method incorporates the use of a portable analyzer to detect the presence of volatile organic vapors at the surface of the interface where direct leakage to atmosphere could occur. The approach of this technique assumes that if an organic leak exists, there will be an increased vapor concentration in the vicinity of the leak, and that the measured concentration is generally proportional to the mass emission rate of the organic compound.

An additional procedure provided in Reference Method 21 is for the determination of "no detectable emissions." The portable VOC analyzer is used to determine the local ambient VOC concentration in the vicinity of the source to be evaluated, and then a measurement is made at the surface of the potential leak interface. If a concentration change of less than 5 percent of the leak definition is observed, then a "no detectable emissions" condition exists. The definition of 5 percent of the leak definition was selected based on the readability of a meter scale graduated in 2 percent increments from 0 to 100 percent of scale, and not necessarily on the performance of emission sources.

Reference Method 21 does not include a specification of the instrument calibration basis or a definition of a leak in terms of concentration. Based on the results of EPA field tests and laboratory studies, methane or hexane is recommended as the reference calibration basis for fugitive emission sources in the natural gas and crude oil production industries.

There are at least four types of detection principles currently available in commercial portable instruments. These are flame ionization, catalytic oxidation, infrared absorption (NDIR), and photoionization. Two types (flame ionization and catalytic oxidation) are know to be available in factory mutual certified versions for use in hazardous atmospheres.

The recommended test procedure includes a set of design and operating specifications and evaluation procedures by which an analyzer's performance can be evaluated. These parameters were selected based on the allowable tolerances for data collection, and not on EPA evaluations of the performance of individual instruments. Based on manufacturers' literature specifications and reported test results, commercially available analyzers can meet these requirements.

The estimated purchase cost for an analyzer ranges from about $1,000 to $5,000 depending on the type and optional equipment. The cost of an annual monitoring program per unit, including semiannual instrument tests and reporting is estimated to be from $3,000 to

$4,500. This estimate is based on EPA contractor costs experienced during previous test programs. Performance of monitoring by plant personnel may result in lower costs. The above estimates do not include any costs associated with leak repair after detection.

An alternative preliminary screening procedure has been added for those sources that can be tested with a soap solution. These sources are restricted to those with nonmoving seals, moderate surface temperatures, without large openings to atmosphere, and without evidence of liquid leakage. The soap solution is sprayed on all applicable sources and the potential leak sites are observed to determine if bubbles are formed. If no bubbles are formed, then no detectable emissions or leaks exist. If any bubbles are formed, then the instrument measurement techniques must be used to determine if a leak exists, or if no detectable emissions exist, as applicable.

The alternative soap solution procedure does not apply to pump seals, sources with surface temperatures greater than the boiling point or less than the freezing point of the soap solution, sources such as open-ended lines or valves, pressure relief valve horns, vents with large openings to atmosphere, and any source where liquid leakage is present. The instrument technique in the method must be used for these sources.

The alternative of establishing a soap scoring leak definition equivalent to a concentration based leak definition is not included in the method and is not recommended for inclusion in an applicable regulation because of the difficulty of calibrating and normalizing a scoring technique based on bubble formation rates. A scoring technique would be based on estimated ranges of volumetric leak rates. These estimates depend on the bubble size and formation rates. A scoring technique would be based on estimated ranges of volumetric leak rates. These estimates depend on the bubble size and formation rate, which are subjective judgments of an observer. These subjective judgments could only be calibrated or normalized by requiring that the observers correctly identify and score a standard series of test bubbles. It has been reported that trained observers can correctly and repeatably classify ranges of volumetric leak rates. However, because soap scoring requires subjective observations and since an objective concentration measurement procedure is available, a soap scoring equivalent leak definition is not recommended for the applicable regulation. The alternate procedure that has been included will allow more rapid identification of potential leaks for more rigorous instrumental concentration measurement.

D.4 REFERENCES

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2. Wetherold, R. and L. Provost. Emission Factors and Frequency of Leak Occurrence for Fittings in Refinery Process Units. Radian Corporation, Austin, TX. For U.S. Environmental Protection Agency, Research Triangle Park, NC. Report Number EPA-600/2-79-044. February 1979. Docket Reference Number A-80-20-B (VOC) II-A-27.*

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7. Brown, G.E., et al. Response Factors of VOC Analyzers Calibrated with Methane for Selected Organic Compounds. U.S. Environmental Protection Agency, Research Triangle Park, NC. Publication No. EPA 600/2-81-002. September 1980. Docket Reference Number A-80-20-B (VOC) II-A-34.*

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9. Emission Test Report: Dow Chemical Company, Plaquemine, La. EMB Report No. 78-OCM-12-c, December 1979. Docket Reference Number A-80-20-B (VOC) II-A-31.*

10. Weber, R.C., et al. "Evaluation of the Walkthrough Survey Method for Detection of Volatile Organic Compound Leaks," EPA Report No. 600/2-81-073, EPA/IERL Cincinnati, Ohio. April 1981. Docket Reference Number A-80-20-B (VOC) II-A-33.*

11. "Data Analysis Report: Emission Factors and Leak Frequencies for Fittings in Gas Plants," EMB Report No. 80-FOL-1. July 1982. Docket Reference Number A-80-20-B (VOC) II-A-36.*

12. "Emission Test Report: Sun Petroleum Products Co., Toledo, OH," EMB Report No. 78-OCM-12B, October 1980. Docket Reference Number A-80-20-B (VOC) II-A-29.*

13. "Emission Test Report: Union Carbide Corporation, Torrance, CA," EMB Report No. 78-OCM-12A, November 1980. Docket Reference Number A-80-20-B (VOC) II-A-30.*

*References can be located in Docket Number A-80-20-B (VOC) at the U.S. Environmental Protection Agency Library, Waterside Mall, Washington, D.C.

APPENDIX E - MODEL FOR EVALUATING THE EFFECTS OF LEAK DETECTION AND REPAIR ON FUGITIVE EMISSIONS FROM PUMPS AND VALVES

E.1 INTRODUCTION

The purpose of Appendix E is to present a mathematical model (LDAR Model) for evaluating the effectiveness of leak detection and repair programs on controlling fugitive emissions from pumps and valves. In contrast to the ABCD model presented in Chapter 4 for analysis of leak detection and repair programs on relief valves and compressor seals, the LDAR model incorporates recently available data on leak occurrence and recurrence and data on the effectiveness of simple in-line repair.[1] In the ABCD model, leak detection and repair program impacts are evaluated through emission correction factors that are based in part upon engineering judgment.

E.2 LDAR MODEL

The LDAR model is based on the premise that all sources at any given time are in one of four categories:

1) Non-leaking sources (sources screening at less than the action level);

2) Leaking sources (sources screening at greater than or equal to the action level);

3) Leaking sources that cannot be repaired on-line and are awaiting a shutdown for repair; and

4) Repaired sources with early leak recurrence.

There are four basic components to the LDAR model:

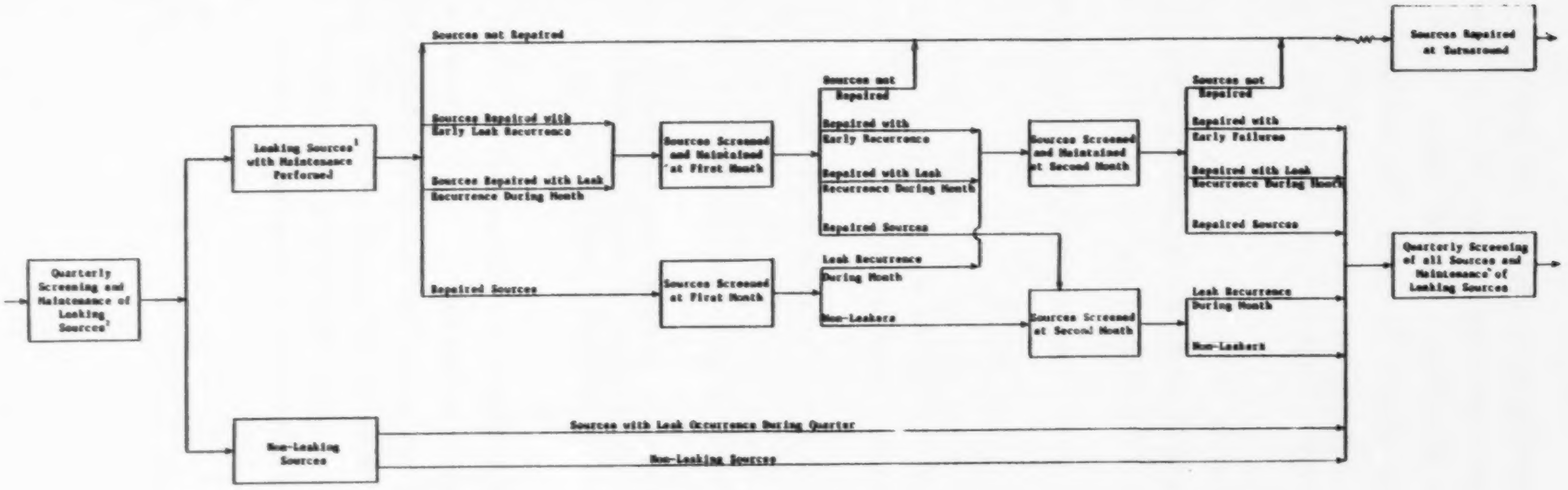
1) Screening of all sources except those in Category 3, above;

2) Maintenance of screened sources in Category 2 and 4 above;

3) Rescreening of repaired sources;

4) Process turnaround during which maintenance is performed for sources in Categories 2, 3, and 4, above. Figure E-1 shows a schematic diagram of the LDAR model.

Since there are only four categories of sources, there are only four "leak rates" for all sources. In fact, there are only three distinct leak rates since the repaired sources experiencing early leak recurrence are assumed to have the same leak rate as sources that were unsuccessfully repaired. The LDAR model does not evaluate gradual changes in leak rates over time but assumes that all sources in a given category have the same average leak rate.


Quarterly Screening and Maintenance of Leaking Sources²
Leaking Sources¹ with Maintenance Performed
Non-Leaking Sources
Sources not Repaired
Sources Repaired with Early Leak Recurrence
Sources Repaired with Leak Recurrence During Month
Repaired Sources
Sources Screened and Maintained at First Month
Sources Screened at First Month
Sources not Repaired
Repaired with Early Recurrence
Repaired with Leak Recurrence During Month
Repaired Sources
Leak Recurrence During Month
Non-Leakers
Sources Screened and Maintained at Second Month
Sources Screened at Second Month
Sources not Repaired
Repaired with Early Failures
Repaired with Leak Recurrence During Month
Repaired Sources
Leak Recurrence During Month
Non-Leakers
Sources with Leak Occurrence During Quarter
Non-Leaking Sources
Sources Repaired at Turnaround
Quarterly Screening of all Sources and Maintenance of Leaking Sources

[1] Leaking sources include all sources which had leak recurrence, had experienced early failures, or had leak occurrence and remained leakers at the end of the preceding quarter.

[2] Except sources for which attempted maintenance was not successful.

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Figure E-1. SCHEMATIC DIAGRAM OF THE LDAR MODEL

The LDAR model is implemented by a statistical analysis LDAR system computer (SAS) computer program enabling investigation of several leak detection and repair program scenarios. General inputs pertaining to the leak detection and repair program may vary (for example, frequency of inspection, repairs, and turnarounds). Further, input characteristics of the emission sources may vary. Inputs required in the latter group include:

1) The fraction of sources initially leaking;

2) The fraction of sources that become leakers during a period;

3) The fraction of sources with attempted maintenance for which repair was successful;

4) The emission reductions from successful and unsuccessful repair.

Other assumptions associated with the model are:

1) All repairs occur at the end of the repair period; the effects associated with the time interval during which repairs occur are negligible;

2) Unsuccessfully repaired sources instantaneously fall into the unrepaired category;

3) Leaks other than unsuccessful maintenance and early recurrences occur at a linear rate with time during a given inspection period;

4) A turnaround essentially occurs instantaneously at the end of a turnaround period and before the beginning of the next monitoring period; and

5) The leak recurrence rate is equal to the leak occurrence rate; sources that experience leak occurrence or leak recurrence immediately leak at the rate of the "leaking sources" category.

E.3 MODEL OUTPUTS

The outputs from the LDAR model are summarized in Table E-1 for three leak detection and repair scenarios for valves (quarterly, monthly/quarterly, and monthly) and two scenarios for pumps (quarterly and monthly).[2] These scenarios enabled estimation of emission reductions and costs for valves and pumps under Regulatory Alternatives II, III, and IV. These estimates are presented in Chapters 7 and 8.

Table E-1. RESULTS OF THE LDAR MODEL LEAK DETECTION AND REPAIR PROGRAMS

Emission source and LDR scenario	Emission factor, kg/day	Percent emission reduction	Total fraction of sources screened in second turnaround - annual average	Fraction of sources operated on in second turnaround - annual average
Valves				
Quarterly	0.041 (0.11)	77	4.0	0.19
Monthly/Quarterly	0.041 (0.11)	78	4.3	0.19
Monthly	0.029 (0.079)	84	11.9	0.19
Pumps				
Quarterly	0.50 (0.63)	58	4.0	0.39
Monthly	0.42 (0.53)	65	12.0	0.41

XX = VOC emission values.
(XX) = Total hydrocarbon emission values.

E.4 REFERENCES

1. Wetherold, R. G., G. J. Langley, et. al. Evaluation of Maintenance for Fugitive VOC Emissions Control. EPA/IERL EPA-600/52-81-080. May 1981. Docket Reference Number II-A-11.*

2. Memorandum. T.W. Rhoads, Pacific Environmental Services, Inc., to Docket A-80-20. Evaluation of the Effects of Leak Detection and Repair on Fugitive Emissions in the Onshore Natural Gas Processing Industry Using the LDAR Model. November 1, 1982. Docket Reference Number II-B-18.*

*References can be located in Docket Number A-80-20-B at the U.S. Environmental Protection Agency Library, Waterside Mall, Washington, D.C.

APPENDIX F - DOCKET ENTRIES ON CORRELATION BETWEEN COST-EFFECTIVENESS AND THROUGHPUT FOR SMALL GAS PLANTS

Attached as Appendix F are two docket entries that develop a correlation between cost-effectiveness and throughput for the recommended new source performance standard controls for pump seals, valves, and pressure relief valves. This analysis is only valid for small gas plants that do not fractionate mixed natural gas liquids into separate products. Two major assumptions used in this analysis are that throughput can be related to emissions for small plants and that small non-complex gas plants would use off-site personnel to implement a leak detection and repair program. These docket entries are included here to enable interested parties to review the basis for the recommended small size cutoff for gas plants without having to obtain copies from the docket.

MEMORANDUM

DATE: November 8, 1982

TO: Docket A-80-20

FROM: Tom Norwood, PES, Inc. TN

SUBJECT: Cost-Effectiveness as a Function of Throughput for Small Gas Plants

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In a meeting with EPA on August 18, 1982, representatives of Allied Corporation (Union Texas Petroleum Corporation) indicated that the leak detection and repair programs required by the recommended NSPS for VOC fugitive emissions for on-shore natural gas processing plants would have to be performed by corporate staff engineers rather than plant personnel. Allied indicated in NAPCTAC testimony that to ensure the program was properly implemented, the cost of such a program would be $15,000 annually as opposed to the $2,070 indicated by EPA (Attachment I). It was assumed that Allied's estimates were based on 1982 dollar values.

Given that central office personnel may be required to perform the program, the cost estimates prepared by Allied were examined for reasonability and corrected to 1980 dollar values as described in Attachment II. The Allied estimates seem to be slightly excessive, as follows:

(1) Inspector Labor: Assuming a plant has 256 valves, relief valves, and pump seals subject to the leak detection and repair program (BID Model Plant A), the complete inspection should take less than 5 hours, as opposed to the two days predicted by Allied. This time is illustrated in Table 1. Eight hours should be allowed, however, to cover travel time and preparation for testing. Four extra hours are allowed for return air travel. Thus, a total of 1½ days is considered realistic.

(2) Travel living expense--since only one day in the field is required, the living expense should be approximately: (1980 dollars)

Car	$34
Living Expense	57
Total	$91

In the administrative cost portion, no additional travel expense is required. As such, the Allied estimates were adjusted as shown in Table II, and annual costs calculated for monthly inspections. The cost of replacement pump seals and of amortized initial repairs are added to the EPA estimate.

As the cost incurred for routine leak detection and repair is relatively fixed for small plants, the control cost effectiveness is primarily a function of plant emissions. As such, a limiting plant size can be determined for a given cost effectiveness. Table III presents the emissions reductions for a small plant as presented in BID Table 7-2. Based on the component mixture used in this small plant, the average emissions reduction for monthly leak detection and repair was determined to be 82 percent. As the cost effectiveness is a function of the amount of VOC removed, a graph of cost effectiveness versus emissions reduction can be made (Figure 1).

Based on the source tests performed by EPA for small gas plants, the VOC emissions can be related to throughput as:

$$\text{VOC Emissions (Mg/yr)} = \text{throughput (MMscfd)}^{1}$$

THC emission reductions can be calculated from Table III as (for model plant A):

$$\text{THC reduction} = \frac{116 \text{ Mg THC}}{40.2 \text{ Mg VOC}} \times \text{VOC reduction}$$

$$\text{or THC} = 2.9 \times \text{VOC}$$

Cost effectiveness is equal to the annualized cost divided by the emissions reduction. The annualized cost is reduced by the value of the products retained in the process. Based on the BID, the VOC value was established as \$192/Mg and the methane-ethane value was \$61/Mg.

Since the emissions reduction for monthly monitoring was 82 percent, the net annual cost =

$$\text{COST (\$/yr)} = \$15{,}013 \text{ (from Table III)} - [\$61 \times (\text{THC} - \text{VOC}) + \$192 \times \text{VOC}] \times 0.82$$

The cost effectiveness is:

$$\text{CE (\$/Mg)} = \frac{\$15{,}013 - [61\ (1.9 \times \text{VOC}) + 192 \times (\text{VOC})] \times 0.82}{0.82 \times \text{VOC}}$$

$$= \frac{\$18{,}300}{\text{MMscfd}} - 300$$

---

[1] Memorandum, K.C. Hustvedt, EPA to J. F. Durham, EPA; "Estimation of VOC Emissions as a Function of Throughput for Small Gas Plants"; November 5, 1982. Docket Reference Number II-B-24.

Using these relationships, cost effectiveness can be calculated for any plant throughput. Figure 1 presents a curve of cost effectiveness of the recommended leak detection and repair program as a function of gas plant capacity. This curve can be used to select a plant size cutoff.

Table I. LEAK DETECTION TIME REQUIREMENTS
(Model Plant A)

Component	Number in Plant	Min/Component[a]	Total Minutes
Valves	250	1	250
Relief Valves	4	8	32
Pump Seals	2	5	10
	Total		292 minutes = 4 hrs 52 min

[a] BID Chapter 8, 2-man team.

TABLE II
COMPARISON OF EPA AND ALLIED
LEAK DETECTION AND REPAIR COSTS ESTIMATES FOR RECOMMENDED NSPS
MONITORING WITH OUTSIDE PERSONNEL

	Allied Estimate (1982 $)		EPA Estimate (1980 $)	
Plant Inspection Costs for Each Trip				
Mechanic	8 hrs	$200	8 hrs	$144
Inspector	16 hrs	384	12 hrs	216
Air Travel		200		167
Car	2 days	80	1 day	34
Living	2 days	100	1 day	57
Sub Total		$964		$618
Additional Administrative Costs for Each Trip				
By Inspector				
1 day in office		$192		$144
1/3 day in plant		64		not required
Travel Expense		30		not required
Subtotal		$286		$144
Total Cost per Sample Period		$1,250		$762
Annual Costs				
Instrument Costs (BID Basis)		$ 5,500		$5,500
Monthly Inspection		$15,000		$9,144
Other Costs Not Considered By Allied				
Replacement Seals Pumps				114
Amortized Initial Repairs				255
Total Annual Cost		$20,500		$15,013

Basis:

	Allied	EPA
Mechanic (With Overhead)	$25/hr	$18/hr
Salary Technical Staff Person (With Fringes)	$192/day	$18/hr

TABLE III

EMISSIONS REDUCTIONS (MODEL PLANT A)

Component Type	Uncontrolled Emissions kg/day	Monthly LDRP kg/day	Emission Reduction kg/day
Valves	45 (120)	7.3 (20)	37.7 (100)
Relief Valves	1.3 (18)	0.40 (4.4)	0.9 (73.6)
Pump Seals	2.4 (3.0)	0.84 (1.1)	1.6 (1.9)
Total	48.7 (141)	8.54 (35.5)	40.2 (116)
Emissions Reduction*		82% (82%)	

XX = VOC
(XX) = THC

$$*ER = \frac{\text{Uncontrolled Emissions - Controlled Emissions}}{\text{Uncontrolled Emissions}} \times 100\%$$

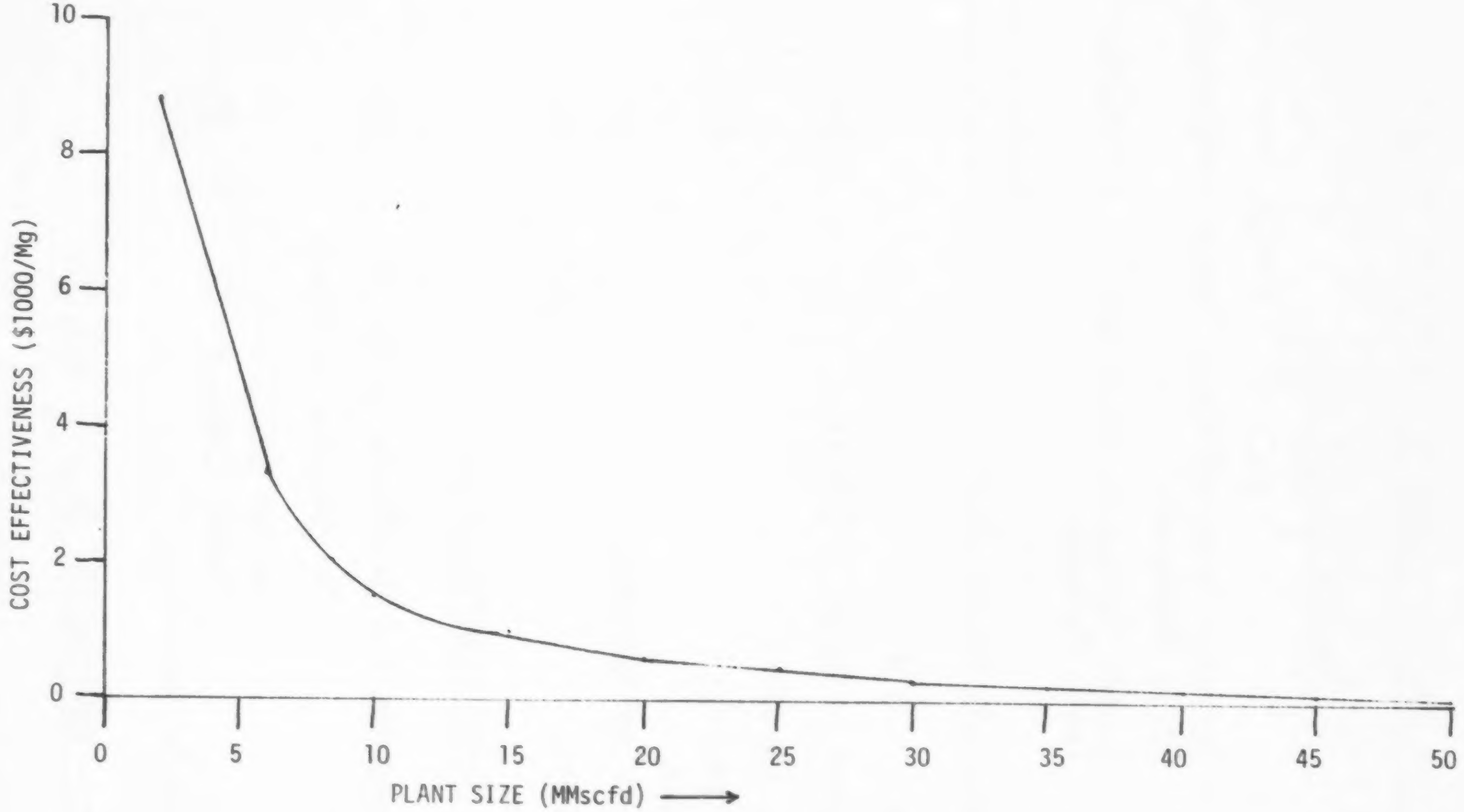

Figure 1 - Cost Effectiveness Vs. Plant Size for Small Gas Plants

Attachment 1

COSTS FOR ROUTINE INSPECTION & REPAIR PROGRAM

FOR ONE SIZE A PLANT

COST BASIS = CONTRACT MECHANIC (WEST TEXAS) = $25/HOUR
(WITH OVERHEADS)

SALARY TECHNICAL STAFF MAN = $192/DAY
(WITH FRINGES)

PLANT MONTHLY INSPECTION TRIP	MONTHLY COST $
MECHANIC - 8 HOURS	200
INSPECTOR - SALARY - 2 DAYS	384
TRAVEL EXPENSES	
AIRLINES	200
CAR	80
LIVING EXPENSES	100
SUB TOTAL	964
ADDITIONAL ADMINISTRATIVE TIME	
BY INSPECTOR - 1 DAY/MONTH IN OFFICE	192
1 DAY/QUARTER IN PLANT	
SALARY ($192 ÷ 3)	64
TRAVEL EXPENSE ($90 ÷ 3)	30
MINIMUM MONTHLY COST	1250

ANNUAL COST - ROUTINE T&I ONLY $15,000

ESTIMATED EPA TOTAL PROGRAM COST $ 2,070

ATTACHMENT II - Derivation of EPA Costs

Assuming Allied costs are 1982 $

Correction Factor: CE Index July 82 314.2[1]
July 80 263.2[2]
Ratio = 1.19

I. Air Travel

Allied = $200

Corrected = 200/1.19 = $167

II. Car

Allied 2 days, $80
(1 day = $40)

Corrected = $40/1.19 = $34

III. Living

Allied 2 days $100
for 1 day, will assume Allied estimate is 1 night motel @ $35.00 and two days expenses @ $32.50/day

Allied for 1 day = 32.50 + 35.00 = $67.50

Corrected = 67.50/1.19 = $57

IV. All labor - will use BID basis of $18/hr
Table 8-5

V. Instrument Costs
will use BID basis of $5,500/yr
(Table 8-9)

References

1 - Chemical Engineering, Vol. 89, No. 21, October 18, 1982

2 - Chemical Engineering, Vol. 87, No. 20, October 6, 1980

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

November 5, 1982

MEMORANDUM

SUBJECT: Estimation of VOC Emissions as a Function of Throughput for Small Gas Plants

FROM: K. C. Hustvedt
Petroleum Section, CPB/ESED

TO: James F. Durham, Chief
Petroleum Section, CPB/ESED

The purpose of this memo is to document the development of a correlation between VOC emissions and throughput capacity for small gas plants. The results of the analysis show that the VOC emissions [in megagrams per year (Mg/yr)] from small gas plants are approximately equal to plant throughput capacity in millions of standard cubic feet per day (MM scfd). This correlation can be used to determine a size cutoff for small gas plants.

In general, there is no relationship between throughput capacity and emissions. Emissions are related to number of pieces of equipment, or process complexity, and process complexity does not consistently relate to throughput capacity. However, as throughput capacity is reduced to relatively small quantities, it seems reasonable to assume that emissions would not remain primarily related to process complexity. If emissions were completely unrelated to throughput capacity, complex plants (Model Plant C) with very small throughput capacities such as one million cubic feet per day would lose a significant portion of their product (almost 10 percent). However, it is likely that these plants would take action to reduce these losses and therefore it is likely that emissions would be less for smaller plants.

The basis used for developing this correlation is the results of the EPA source tests of two relatively small gas plants. Table 1 shows the development of the leaker and nonleaker emission factors for valves, relief valves, and pump seals based on the technique described in EPA-450/3-82-010 (April 1982), "Fugitive Emission Sources of Organic Compounds - Additional Information on Emissions, Emission Reductions, and Costs" (AID). Table 2 and 3 present the development of emission estimates for the two EPA tested small gas plants based on the factors presented in Table 1. Plant 3 (Table 2) emits 89.2 kilograms per day (kg/day) of VOC (32.6 Mg/yr) and has a capacity of 60 MM scfd for a ratio of emissions to throughput of 0.54. Plant 4 (Table 3) emits 120 kg/day (43.9 Mg/yr) of VOC and has a capacity of 30 MM scfd for emissions to throughput ratio of 1.46. The arithmetic average of these two ratios yields the estimation for small gas plants that the VOC emissions in Mg/yr equals the throughput in MM scfd (average ratio equals 1.00).

3 Attachments

Table 1. DEVELOPMENT OF EMISSION FACTORS FOR LEAKING AND NONLEAKING SOURCES IN GAS PLANTS[a]

Source	Overall Emission[b] Factor (kg/day)	Leaker Correction Factor(b,c)	Leaker Emission Factor (kg/day)	Nonleaker Correction Factor(b,d)	Nonleaker Emission Factor (kg/day)
Valves					
(VOC)	0.18	$\frac{86}{18}$	0.86	$\frac{14}{82}$	0.031
(THC)	0.48	$\frac{87}{18}$	2.3	$\frac{13}{82}$	0.076
Relief Valves					
(VOC)	0.33	$\frac{77}{19}$	1.3	$\frac{23}{81}$	0.094
(THC)	4.5	$\frac{77}{19}$	18	$\frac{23}{81}$	1.3
Pump Seals					
(VOC)	1.2	$\frac{79}{33}$	2.9	$\frac{21}{67}$	0.38
(THC)	1.5	$\frac{79}{33}$	3.6	$\frac{21}{33}$	0.95

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[a] Technique described in EPA-450/3-82-010 (April 1982) "Fugitive Emission Sources of Organic Compounds - Additional Information on Emissions, Emission Reduction, and Costs." (AID)

[b] Emission factors and the inputs to the correction factors are from ESED/EMB Report No. 80-FOL-1 (July 1982), "Frequency of Leak Occurrence and Emission Factors for Natural Gas Liquid Plants."

[c] As outlined in the AID, the leaker correction factor is the ratio of the percent of overall emissions from leaking sources divided by the percent of overall sources leaking. This number is multiplied times the overall emission factor to derive the leaker emission factor.

[d] As discussed under footnote "c," the nonleaker correction factor is the ratio of the percent of overall emissions from nonleaking sources divided by the percent of overall sources that are not leaking.

Table 2. ESTIMATED EMISSIONS FOR EPA PLANT TEST NUMBER 3 (60MM scfd capacity)

Source	Total Number Sources	Percent Leaking	Number Leaking	Leaker[a] Emissions (kg/day)	Number Not Leaking	Nonleaker[b] Emissions (kg/day)	Total Emissions (kg/day)
Valves	341	23.6	80	68.8 (184)	261	8.1 (19.8)	76.9 (204)
Pressure Relief Valves	11	90.0	9	11.7 (162)	2	0.2 (2.6)	11.9 (165)
Pump Seals	1	0.0	0	0 (0)	1	0.4 (1)	0.4 (1)
Total				80.5 (346)		8.7 (23.4)	89.2 (370)

XX - VOC Emissions
(XX) - Total Hydrocarbon Emissions
Reference: Fugitive VOC Testing at Houston Oil and Minerals Smith Point Plant. U.S. EPA, ESED/EMB Report No. 80-OSP-1, October 1981.

[a] Based on leaker emission factor derived in Table 1.
[b] Based on nonleaker emission factor derived in Table 1.

Table 3. ESTIMATED EMISSIONS FOR EPA PLANT TEST NUMBER 4 (30MM scfd capacity)

Source	Total Number Sources	Percent Leaking	Number Leaking	Leaker[a] Emissions (kg/day)	Number Not Leaking	Nonleaker[b] Emissions (kg/day)	Total Emissions (kg/day)
Valves	565	16.8	95	81.7 (218)	470	14.6 (35.7)	96.3 (254)
Pressure Relief valves	13	14.3	2	2.6 (36)	11	1.0 (14.3)	3.6 (50.3)
Pump Seals	14	44.4	6	17.4 (21.6)	8	3.0 (7.6)	20.4 (29.2)
Total				102 (276)		18.6 (57.6)	120 (334)

XX - VOC Emissions
(XX) - Total Hydrocarbon Emissions
Reference: Fugitive VOC Testing at the AMOCO Hastings Gas Plant. U.S. EPA, ESED/EMB Report No. 80-OSP-2, July 1981.

[a] Based on leaker emission factor derived in Table 1.
[b] Based on nonleaker emission factor derived in Table 1.

APPENDIX G

REVISED COMPRESSOR SEAL EMISSION FACTORS AND SEAL VENT SYSTEM CONTROL COSTS

Appendix G contains three memoranda that document revisions to the emissions estimates and control cost estimates for compressors. The compressor seal emission factors presented in Chapters 3, 4, 7 and 8 of this document were revised. The original emission factors represented the average emission from all compressors, including those processing dry gas. Because dry gas compressors are not subject to the proposed standards, the emission factors were revised to represent average emissions from wet gas and natural gas liquids compressors, the compressor types that are covered by the proposed standards. The development of the revised emission factors is documented in the memorandum dated February 10, 1983, that is included in this appendix.

After completion of Chapter 8 of this document, the costs for reciprocating compressor seal controls were also revised in response to comments received from industry representatives. The revised costs are presented in the memorandum dated February 23, 1983, that is included in this Appendix. Finally, the effect of control device costs on compressor seal vent enclosure cost effectiveness is included in this appendix in a memorandum dated June 28, 1983.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

February 10, 1983

MEMORANDUM

SUBJECT: Revised Gas Plant Compressor Seal Emission Factor

FROM: K. C. Hustvedt
Petroleum Section, Chemicals and Petroleum Branch, ESED (MD-13)

TO: James F. Durham, Chief
Petroleum Section, Chemicals and Petroleum Branch, ESED (MD-13)

Recommendation

In the February 3, 1983, AA review package for the onshore production new source performance standard (ESED Project No. 80/22A), we included a recommendation to exempt dry gas equipment from the standards. A review of the data used in developing our present compressor seal VOC emission factor (0.36 megagrams per year (Mg/yr) per seal) shows a large portion of the data are from dry gas compressors; therefore, the overall emission factors used in the package were not representative of the population now being regulated. In developing the basis for compressor seal regulations, I recommend that the refinery hydrocarbon service compressor seal VOC emission factor (5.5 Mg/year per seal) be used for natural gas liquids (NGL) service compressor seals and that an estimated emission factor (0.7 Mg/yr per seal) be used for wet gas service compressor seals. Weighting these emission factors based on the occurrence of these compressor seal services in the API and EPA testing yields an average gas plant compressor seal VOC emission factor of 2.3 Mg/yr. Further, using equipment controls to reduce these emissions will essentially eliminate the emissions and, where it is technically feasible, quarterly monitoring will reduce the VOC emissions to 0.4 Mg/yr.

Background

The background information document (BID) for the gas plants NSPS states that the compressor seal emission factor is probably substantially understated. This is because both the EPA and API testing of compressors included only open frame compressor distance piece emissions. No seal packing vents or enclosed distance pieces were tested. In the past, industry has stated that most of the compressor seal emissions will come from the seal packing vent if the compressor has one. They have also stated that enclosing and venting the distance piece is likely to increase compressor seal emissions because the seal is harder to visually inspect for failure and because seal maintenance is more difficult (the enclosure must be removed). These industry comments certainly support our contention that the compressor seal emisson factor could be substantially understated.

Based on comments received at the NAPCTAC meeting that certain sources within gas plants have essentially no VOC emission reduction potential and a subsequent review of the available data, we have recommended that the NSPS include an exemption for dry gas service equipment (defined as less than 1.0 weight percent VOC). Because our data base includes dry gas compressors and because these are likely to have the lowest VOC emissions of the compressors studied, the data base should be reviewed to determine if the emission factors should be corrected to represent only the compressor seals affected by the recommended NSPS.

Review of Available Data

Table 1 shows a summary of the gas plant compressor seal data used to develop the gas plant emission factor. As you can see, there were 71 seals screened and 26 measured for mass emissions. Over one-third of the sources screened and measured were in dry gas service. While deleting the dry gas service data and recalculating a new emission factor based on the remaining data would be possible, this would not necessarily result in a better emission factor due to another shortcoming. As shown in Table 1, 16 of the remaining (non-dry gas) 47 compressor seals, or about one-third are in natural gas liquids (NGL) service and only one of these 16 was tested for mass emissions. Simply calculating a new emission factor based on the existing data base (after removing the dry gas compressors) would greatly understate the VOC emissions from NGL compressor seals because the mass emissions data from wet gas compressors (averaging 6.8 percent VOC) are used to estimate mass emissions from NGL compressors (100 percent VOC in the one compressor tested) in the development of emission factors. For these reasons, different methods should be used to develop emission factors for gas plant compressor seals.

Development of Emission Factors

Because there is a large difference in process stream VOC concentration between NGL and wet gas service compressors as seen in Table 1, emission factors are developed for both services. NGL service compressors contain mixed natural gas liquids, LPG, propane refrigerant, etc., and usually contain greater than 50 percent VOC. In gas plant testing of NGL compressors, 16 were screened for leakage, yet only one seal was tested for mass emissions. Because these limited data are insufficient for direct emission factor calculation, other methods of developing emission factors were investigated. The technique based on percent of sources leaking used to calculate emission factors for chemical plant compressor seals in the AID (Fugitive Emission Sources of Organic Compounds: Additional Information on Emissions, Emission Reductions, and Costs, EPA 450/3-82-010, April 1982) could be used, but it was felt that the 83 percent (5 of 6) NGL service compressor seals leaking found by EPA was not representative of the natural gas processing industry. These NGL service compressors are, however, essentially identical to hydrocarbon service compressors in petroleum refineries and thus the refinery compressor seal VOC emission factor of 15 kg/day (5.5 Mg/yr) will be used for gas plant NGL service compressor seals.

For wet gas service compressors, it appears as though sufficient data are available to use the AID techniques to calculate an emission factor. Fourteen out of 30, or 46.7 percent, of the wet gas service compressor seals leaked. Using the procedure outlined in Section 2 of the AID, this leak frequency translates into an emission factor of 19.2 kg/day (7.0 Mg/yr) as shown in Table 2. This factor, however, is for total hydrocarbon emissions (THC) and only a portion of the wet gas service compressor seal THC emissions would be VOC. Based on an estimated average VOC concentration of 10 weight percent, the wet gas service compressor seal VOC emission factor would be 1.9 kg/day (0.70 Mg/yr).

To obtain an overall gas plant compressor seal emission factor, the weighted average of the wet gas and NGL service emission factors are used. As shown in Table 1, 66 percent (31 of 47) of the seals screened were in wet gas service and 34 percent (16 of 47) were in NGL service. Weighting the individual emission factors by these percentages yields an average emission factor for gas plant compressor seals of 6.4 kg/day (2.3 Mg/yr) of VOC and 18 kg/day (6.6 Mg/yr) of THC.

Emission Reductions

In the calculation of the emission reduction obtained through control of gas plant compressor seals, 100 percent control is estimated for equipment controls. In the CTG, however, quarterly monitoring is allowed where it is technically feasible. In calculating the ABCD estimated emission reduction, the B, C, and D values from Table 7-1 of the Refinery BID (EPA 450/3-81-015a, November 1982) are used because the refinery compressor seal data form the basis for the new gas plant compressor seal emission factors. A weighted average A factor for wet gas and NGL service compressor seals is used. For NGL the A factor is 0.91 (Refinery BID) and for wet gas compressors the A factor is 0.94 [18026 kg/day per thousand seals (leaker emissions from Table 2) divided by 19172 kg/day per thousand seals (total emissions in Table 2)]. Weighting these A factors as was done for the overall emission factor yields an average A factor of 0.93. Overall emission reduction is therefore calculated as follows:

$$\begin{aligned}\text{Emission Reduction} &= A \times B \times C \times D \\ &= 0.93 \times 0.90 \times 0.98 \times 0.98 \\ &= 0.80\end{aligned}$$

This estimated 80 percent emission reduction is then corrected as was explained in the AID and the Gas Plant BID to lessen the impact of the estimated B factor on the overall estimate. As was determined in T. Rhoads (PES) November 1, 1982, memo, "Calculation of Controlled Emission Factors for Pressure Relief Valves and Compressor Leaks", the VOC correction factor is 1.04 and the THC correction factor is 1.01. Using these correction factors, the estimated emission reductions for quarterly monitoring of gas plant compressor seals is 83 percent for VOC emissions and 81 percent for THC emissions. This equates to controlled emission factors of 0.4 Mg/yr VOC and 1.2 Mg/yr THC after implementation of a quarterly leak detection and repair program.

cc: Dianne Byrne, SDB
Fred Dimmick, SDB
Tom Norwood, PES
Tom Rhoads, PES
Bruce Tichenor, ORD/RTP

Table 1. GAS PLANT COMPRESSOR SEAL DATA SUMMARY

Service	Number Screened	Number Emitting[a]	Number Leaking[b]	Number Measured[c]	Percent VOC[d]
--API DATA--					
Dry gas[e]	24	18	--	9	0.42
Wet gas[f]	1	0	--	0	--
NGL [g]	10	9	--	0	--
--EPA DATA--					
Dry gas	0	0	0	0	--
Wet gas	30	19	14	16	6.8
NGL	6	5	5	1	100
--OVERALL--	71	51	--	26	6.3

REFERENCE: "Frequency of Leak Occurrence and Emission Factors for Natural Gas Liquid Plants." - EMB No. 80-FOL-1, July 1982.

(a) Emitting sources are ones that showed any evidence of leakage when screened.

(b) Leaking sources screened greater than 10,000 ppm.

(c) Sources measured for mass emissions.

(d) Total measured VOC emissions divided by total hydrocarbon emissions X 100.

(e) Dry gas is field natural gas after the natural gas liquids are removed.

(f) Wet gas is field natural gas.

(g) NGL is natural gas liquids including raw NGL mix, LPG, propane refrigerant, etc.

Table 2. Calculation of Gas Plant Wet Gas Service Compressor Seal Emission Factors

	Number of Sources Per 1000	Emission Factor[b] (kg/day)	Emissions Per 1000 Sources (kg/day)
Leaking Sources	467[a]	38.6	18026
Non-Leaking Sources	533	2.15	1146
Total	1000		19172[c]

(a) From Table 1, 14 of 31 or 46.7 percent of wet gas service compressor seals were leaking in the EPA testing.

(b) Leaking and non-leaking source emission factors were developed in the AID (p 2-62).

(c) The resulting overall average emission factor per sources would therefore be 19.2 kg/day or 5.0 Mg/yr. This factor however, estimates the total hydrocarbon emissions. Based on an average wet gas VOC content of 10 weight percent, the VOC emission factor for wet gas compressor seals becomes 1.9 kg/day (0.7 Mg/yr).

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

A-80-20-B(VOC)
II-B-37

February 23, 1983

MEMORANDUM

SUBJECT: Revised Cost Analysis for Reciprocating Compression Seal Vent Controls

FROM: Kent C. Hustvedt Kent
Petroleum Section, CPB (MD-13)

TO: James F. Durham, Chief
Petroleum Section, CPB (MD-13)

Over the past several months many changes have been made in our configuration and cost basis for controlling gas plant reciprocating compressor seals. These changes have been made in our continuing effort to design and cost a safe, realistic system for control of compressor seal emissions. While the system described and analyzed in the background information document (BID) is basically adequate, information recently supplied to us by Union Texas Petroleum (UTP) shows that several oversights were made in our analysis. Table 1 summarizes revised capital costs for the reciprocating compressor seal control systems based on our review of UTP's submittal. A contingency of 10 percent has been added to the capital costs and they have been annualized as in the BID. These costs will be used to assess the cost and cost-effectiveness of compressor seal vent control systems for the gas plant NSPS and CTG.

Table 2 is a detailed listing of the capital costs of the reciprocating compressor seal control system. Table 2 is a revision of an order of magnitude cost estimate made by UTP and supplied to us in a letter from Bill Taylor of UTP to Susan Wyatt dated February 8, 1983, (Docket No. 80-20-B, II-D-53). I have revised their cost estimates as follows: (1) their costs were corrected using cost indices to make them consistent with our year basis (1980), (2) our vendor quote equipment costs were used as documented in the BID, and (3) reasonable alternative equipment were used. Justifications for the use of the alternative equipment are provided as references to the table.

Attachment

cc: Dianne Byrne, SDB
Fred Dimmick, SDB
Tom Norwood, PES
Tom Rhoads, PES
Bruce Tichenor, ORD/RTP

Table 1 - Summary of Reciprocating Compressor Control System Costs (1980 $)

Item	Capital Cost (a)	Capital Costs With Contingency (b)	Annual Costs (c)
Double Distance Piece	2500	2750	700
Distance Piece Piping	1000	1100	280
Instrumentation For Purge Gas	1780	1960	500
Flare	6670	7340	1860
Flare Piping	3380	3700	940

(a) Revised capital costs based on our review of the February 8, 1983, Union Texas Petroleum submittal (Table 2).

(b) Total capital costs including 10 percent contingency.

(c) Annualized capital costs based on 0.163 capital recovery factor (10 percent interest rate and 10 year lifetime), 0.05 x capital costs for maintenance and 0.04 x capital costs for taxes, insurance, and administration.

EPA REVISION TO UTP COSTS
2/16/83

TABLE 2
ORDER OF MAGNITUDE ESTIMATE FOR COMPRESSOR SEAL LEAK CONTROLS*

	Cost Per Cylinder	~~Cost Per Model A Plant~~
Incremental Cost for Double Distance Piece	~~$3,000~~ 2500 Ⓐ	~~$6,000~~
~~Extention of Compressor Skid & Foundation~~	~~$ 500~~	~~$1,000~~

Distance Piece Piping	Material	Labor (18.85/Manhour)	LABOR CORRECTION FACTOR $\left(\frac{18.00}{18.85}\right)$
1" Piping - ~~100 Ft.~~ 31 m. @ ~~$2.00/Ft.~~ $2.82/m	~~$200~~ 90	$300	
1" Check Valves - ~~2~~ 1 @ 80	~~$500~~ 80	$ ~~60~~ 30	
1" Block Valves - 2 @ 25	~~$200~~ 50	$ 60	650 $\xrightarrow{(1980\$)}$ 620
Ⓑ ~~Oil Seal Pot~~	~~$800~~	~~$200~~	
Misc. Flanges, Fittings, Etc.	~~$200~~ 160	$ 50	
Indirects		$210	
	~~$1,900~~ 380	$ ~~880~~ 620	

Sub-Total ~~$2,800~~ 1000 ~~$5,600~~

Instrumentation For Purge Gas	Material	Labor	
Ⓑ OIL SEALPOT	800	200	
Ⓒ ~~Inlet Control Valve~~	~~800~~	~~50~~	
SUPPLY REGULATOR (vendorquote)	350	50	
~~Controller~~	~~1100~~	~~270~~	
Ⓓ ~~Back Pressure Control Valve~~	~~800~~	~~50~~	580 $\xrightarrow{1980\$}$ 550
~~Controller~~	~~1100~~	~~270~~	
1" Block Valves - 2@25	~~200~~ 50	60	
1" Piping - ~~25 Ft.~~ 8m @ 2.82/m	~~50~~ 20	25	
Misc. Flanges, Fittings (1980$)	~~200~~ 160	50	
Indirects		195	
	~~$4,250~~ 1230	$ ~~950~~ 550	

Sub-Total ~~$5,200~~ 1780 ~~$5,200~~

*Attachment to a letter from Bill Taylor (UTP) to Susan Wyatt (EPA), dated 2/3/83. (EPA docket number A-80-20-B, II-D-53)

	Material	Labor		Cost Per Cylinder	~~Cost Per~~ ~~Model A Plant~~
Cost of ~~2 mm SCFD~~ Flare (1980 $)				~~$25,000*~~ ~~$000~~ → 6670 Ⓔ	~~$25,000*~~
Piping To Flare					
Ⓕ ~~Residue Gas To Flare~~ ~~500 Ft. - 2" Pipe @ $3/Ft.~~	~~1500~~	~~1600~~			
Inlet Line from Compressor to Flare ~~500 Ft~~ 100m. - 2" Pipe @ ~~$3/Ft.~~ 6.50/m	~~1500~~ 650	1600(× $\frac{300}{500}$) 960			
Ⓖ Rupture Disk (vendor quote)	~~550~~ 130	50	1520 $\xrightarrow{\frac{146}{3}}$ 1450		
Misc. Flares, Fittings (1980 $)	1230 ~~1500~~(× $\frac{300}{1000}$) 370	500(× $\frac{300}{1000}$) 150			
Indirects		1200(× $\frac{300}{1000}$) 360			
	~~5050~~ 1180	~~4950~~ 1450			
Sub-Total				~~$10,000~~ 2630	~~$10,000~~
Misc. Costs For Pipe Supports (1980 $)				$ 2500 ~~3,000~~ (× $\frac{300}{1000}$) 750	~~$ 3,000~~
				3380	
~~Total Materials & Labor~~				~~$49,000~~	~~$55,800~~
~~Contingency - 20%~~				~~$ 9,500~~	~~$11,200~~
~~Total Cost~~				~~$59,000~~	~~$67,000~~
~~Adjustment For 1982 vs. 1980 Costs (- 20%)~~					~~$55,800~~
~~Adjustment to EPA Cost for Double Distance Piece - $2,000 each~~					~~$53,800~~

References for Table 2

A. Telephone conversation report. T. Norwood, Pacific Environmental Services, Inc., with P. Marthinetti, Ingersoll-Rand. December 8, 1982. Distance piece price verified by Mr. Marthinetti as $2,000 to $3,000 (1980). Average value of $2,500 used. Docket Reference Number II-E-19.*

B. Single oil seal pot required for all compressors instead of one per compressor.

C. Telephone conversation. T. Norwood, Pacific Environmental Services, Inc., with D. Rudolph, Fairchild Industries. Price of natural gas supply regulator. Docket Reference Number II-E-22.*

D. These costs are already included in flare cost.

E. Letter, R.W. Kreutzen, Chevron U.S.A. to J.R. Farmer, EPA:CPB, "Draft CTG for Natural Gas Processing Plants," March 12, 1982. 1982 installed cost of flare given as $8,000. Deflated to 1980 dollars = $6,670. Docket Reference Number II-D-32.*

F. Pilot gas for flare not needed as compressor vent stream is the pilot. Flare is auto ignited type.

G. Telephone conversation. T.L. Norwood, Pacific Environmental Services, Inc., with Continental Disk Co., February 14, 1983. Quote of $100/holder and $64/disk corrected to June 1980 dollars = $52/disk and $82/holder. Docket Reference Number II-E-23.*

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*References can be located in Docket Number A-80-20-B at the U.S. Environmental Protection Agency Library, Waterside Mall, Washington, D.C.

A-80-20-B(VOC)
II-B-44

MEMORANDUM

DATE: June 28, 1983

TO: K.C. Hustvedt

FROM: T.L. Norwood, PES, Inc. TLN

SUBJECT: Effect of Control Device Costs on Compressor Seal Vent Enclosure Cost Effectiveness

Prior to preparation of the current draft of the new source performance standard for equipment leaks of VOC from natural gas processing plants, representatives from Union Texas Petroleum indicated that not all gas plants have operating flares. They contended that the cost effectiveness of controlling compressor seal leaks by using enclosed distance pieces should be adjusted to include the cost of the control device in the enclosure costs.[1]

As some plants do use operating flares, the costs and cost effectiveness for compressor seal vent controls in plants both with and without control devices present (Model Plant B) were calculated. These calculations were performed for two types of compressors (centrifugal and reciprocating) in either of two types of service (wet gas or natural gas liquids).

Table 1 presents the cost and cost effectiveness for the eight resulting cases. As can be seen, the cost effectiveness varies from $36/Mg for the best case (centrifugal compressors in NGL service with existing control devices) to $2200/Mg for the worst case (reciprocating compressors in wet gas service with a new control device).

Table 2 presents the capital cost calculations required to develop Table 1.

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[1] Memo, T.L. Norwood to Dianne Byrne EPA:SDB, January 27, 1983, "Meeting to Discuss Industry Comments on the Draft NSPS for Natural Gas Processing Plants." Docket Index No. II-E-24.

Table 1. COSTS AND COST-EFFECTIVENESS FOR COMPRESSOR VENT CONTROL SYSTEM FOR MODEL PLANT B

Compressor Type[a]	Control Device Present[b]	Compressor[c] Service	Capital Cost[d] ($1,000)	Annual Cost[e] ($1,000/yr)	Emission Reduction[f] (Mg/yr)	Cost Effectiveness[g] ($/Mg)
Centrifugal	yes	wet gas	4.7	1.2	4.2	280
		NGL			33	36
	no	wet gas	12.0	3.0	4.2	710
		NGL			33	91
Reciprocating	yes	wet gas	29.0	7.3	4.2	1,700
		NGL			33	200
	no	wet gas	36.0	9.1	4.2	2,200
		NGL			33	280

---

[a] Centrifugal compressors are driven by rotating shafts while reciprocating compressors are driven by shafts having a linear motion.

[b] "Yes" indicates that a control device is present at the plant. The cost of a control device (flare) has been added to the compressor vent control system costs for plants without an existing control device.

[c] Wet gas means field gas with an average VOC content of 10 percent by weight NGL (Natural gas liquids) consists of mixed liquids separated from wet gas (i.e., liquid petroleum gas).

[d] Capital costs per Table 2.

[e] Annualized cost = CAPITAL RECOVERY + MAINTENANCE COSTS + MISCELLANEOUS COSTS

$$= [.163 + .05 + .04] \times \text{CAPITAL} = 0.253 \times \text{CAPITAL COST (BID Table 8-5).}$$

[f] From BID Appendix G, page G-2, Emission reduction based on six seals in Model Unit B.

[g] $$\text{Cost Effectiveness} = \frac{\text{Annual Cost}}{\text{Emission Reduction}}$$

Table 2. COMPRESSOR SEAL VENT SYSTEM CAPITAL COSTS (Model Plant B)

Item	Centrifugal Compressors	Reciprocating Compressors[a]
Double Distance pieces		16,500[c]
Seal Vent Piping	924[b,c]	6,600[c]
Purge Gas Supply		1,960
Flare Piping	3,700[a]	3,700
Subtotal[d]	4,624	28,760
Flare	7,340[a]	7,340
Total[e]	11,964	36,100

---

[a] From BID Appendix G, page G-10, Table 1.

[b] From BID Table 8-1.

[c] Costs are for six compressor seals.

[d] Total capital costs for plants with existing control devices.

[e] Total capital costs for plants without existing control devices.

APPENDIX H

CALCULATION OF EMISSION REDUCTIONS AND COST EFFECTIVENESS FOR THE PROPOSED STANDARDS BY SOURCE TYPE

Chapter 6 of this document presents the model plants and regulatory alternatives on which the emission reductions and costs impacts in Chapters 7 and 8 were determined. The proposed standards however, are not based on a single regulatory alternative; they are based on selected control strategies from different alternatives for each component. Consequently, this appendix documents the emission reductions and cost effectiveness of alternative controls and the proposed standards by source type for Model Plant B.

M E M O R A N D U M

TO: Docket A-80-20B DATE: May 26, 1983

FROM: T.L. Norwood and D.G. Cole TLN

SUBJECT: Costs and VOC Emission Reduction for the Recommended Standards of Performance for Equipment Leaks of VOC in Onshore Natural Gas Processing Plants (ESED Project No. 80/22)

- -

The purpose of this memo is to document the costs and VOC emission reductions for the New Source Performance Standards for onshore natural gas plants (VOC) recommended for proposal. This is necessary because the standards for each fugitive emission source are based on the selection of control techniques rather than regulatory alternatives. Table 1 provides a summary of the Model Plant B emission reductions and the average and incremental cost effectiveness of various controls for each fugitive emission source. The control techniques that are underlined in Table 1 were selected as the basis for the standards because the incremental cost-effectiveness numbers were judged to be reasonable.

Tables 2 through 7 provide a detailed breakdown of the analyses used to produce Table 1. All information in the tables is from the BID for the proposed standards, and footnotes at the end of each table explain how the numbers were calculated. All of the tables except Table 3 for compressor seals are based on the control of a single component because there are no economies of scale. The compressor cost analysis in Table 3 was performed for Model Plant B because there are fixed costs for the system.

cc: K.C. Hustvedt
Dianne Byrne

Table 1. EMISSIONS REDUCTIONS AND CONTROL COST EFFECTIVENESS FOR MODEL PLANT B

Source	Control Technique	Emission Reduction[b] (Mg/yr)	Average Cost Effectiveness[a] ($/Mg)	Incremental Cost Effectiveness[a] ($/Mg)
Pressure relief devices	Quarterly leak detection and repair[d]	0.95	--[c]	--[c]
	Monthly leak detection and repair	1.0	0	5,800
	Rupture disks[e]	1.5	6,700	22,000
Compressors	Closed-vent and seal system[d]	14[f]	460	460
Open-ended valves and lines	Caps[d]	19	--[c]	--[c]
Sampling connection systems	Closed-purge sampling	0.22	7,000[e]	7,000[e]
Valves	Quarterly leak detection and repair	40	--[c]	--[c]
	Monthly leak detection and repair[d]	43	0	1,400
Pumps	Quarterly leak detection and repair	1.5	830	830
	Monthly leak detection and repair[d]	1.7	900	1,500
	Dual mechanical seals[e]	2.6	4,900	12,000

---

[a] From Tables 2 through 7 of this memo.

[b] From BID Table 7-2.

[c] Cost savings occur.

[d] Control techniques selected as the basis for the recommended standards.

[e] Impacts shown are weighted averages based on 180 new plants and 40 modified/reconstructed plants.

[f] From Reference 2.

Table 2. ANNUALIZED CONTROL COSTS PER COMPONENT
FOR PRESSURE RELIEF DEVICES[a]
(June 1980 Dollars)

	CONTROL TECHNIQUE			
	Quarterly Inspections	Monthly Inspections	Rupture Disks (new)	Rupture Disks (Retrofit)
Installed Capital Cost	0	0	3,100[b]	4,200[b]
Annualized Capital				
A. Control Equipment	--[c]	--[c]	600[d]	780[d]
B. Initial Leak Repair[e]	0	0	0	0
Annualized Operating Costs				
A. -Maintenance[f]	--[c]	--[c]	160	210
B. Miscellaneous[g]	--[c]	--[c]	120	170
C. Labor				
1. Monitoring[h]	19	58	0	0
2. Leak Repair[e]	0	0	0	0
3. Administrative and Support[i]	7.6	23	0	0
Total Annual Cost Before Credit	27	81	880	1,160
Recovery Credit[j]	73	81	116	116
Net Annualized Costs[k]	(46)	0	760	1,040
Total VOC Emission Reduction (Mg/yr)[l]	0.076	0.084	0.12	0.12
Cost Effectiveness ($/Mg VOC)[m]	(610)	0	6,300	8,700
Incremental Cost Effectiveness[n] ($/Mg VOC)	(610)	5,800	21,000	29,000

Table 2. ANNUALIZED CONTROL COSTS PER COMPONENT FOR PRESSURE RELIEF DEVICES[a] (June 1980 Dollars) (Concluded)

Footnotes:

[a] All costs and emission reduction estimates are for one piece of equipment in VOC service.

[b] See BID Table 8-1. Assume 1/2 of relief valves controlled by rupture disks with 3-way valves and 1/2 with rupture disk/block valve. $\frac{1995 + 4116}{2} = 3100$ (new); $\frac{3631 + 4764}{2} = 4200$ (retrofit)

[c] Cost of monitoring instrument is not included in this analysis.

[d] Obtained by multiplying capital recovery factor (2 years, 10 percent interest = 0.58) by capital cost for rupture disk and capital recovery factor (10 years, 10 percent interest = 0.163) by capital cost for all other equipment (rupture disk holder, piping, valves, pressure relief valve).

New installation cost = 0.163 (3100 - 230) + 0.58 (230) = 600

Retrofit installation cost = 0.163 (4200 - 230) + 0.58 (230) = 780

[e] Leaks are corrected by routine maintenance in the absence of the standards; therefore, no cost is incurred for repair.

[f] 0.05 x capital cost.

[g] 0.04 x capital cost.

[h] Monitoring labor hours (i.e., number of workers X number of components x time to monitor x times monitored per year) x $18 per hour. Assumes 2-man monitoring team per relief valve, 8 minutes monitoring time per valve, monitored quarterly or monthly.

[i] 0.40 x (monitoring cost + leak repair cost).

[j] Recovery credit based on uncontrolled VOC emission factor of 0.33 kg/day and total hydrocarbon emission factor of 4.5 kg/day and recovered VOC value of $192/Mg and recovered non-VOC hydrocarbon (methane-ethane) value of $61/Mg from Table 8-5. Based on 63 percent control efficiency for quarterly inspections, 70 percent control efficiency for monthly inspections, and 100 percent control efficiency for rupture disks.

[k] Total annual cost (before credit) minus recovery credit.

[l] Based on uncontrolled VOC emission factor and control efficiencies for each control technique in footnote j.

[m] Obtained by dividing net annualized cost by total VOC emission reduction.

[n] Incremental dollars per megagram = (net annual cost of control technique - net annual cost of next less restrictive control) divided by (annual reduction of next less restrictive control).

Table 3. ANNUALIZED CONTROL COSTS FOR COMPRESSOR SEALS - MODEL PLANT B[a] (June 1980 Dollars)

	CONTROL TECHNIQUE
	Closed vent and seal system
Installed Capital Cost[b]	25,100
Annualized Capital Control Equipment[c]	4,100
Annualized Operating Costs	
A. Maintenance[d]	1,300
B. Miscellaneous[e]	1,000
Total Annual Cost Before Credit	6,400
Recovery Credit[f]	0
Net Annualized Cost[g]	6,400
Total VOC Emission Reduction (Mg/yr)[h]	14
Cost Effectiveness ($/Mg VOC)[i]	460

Table 3. ANNUALIZED CONTRTOL COSTS FOR COMPRESSOR SEALS - MODEL PLANT B[a] (June 1980 Dollars) (Concluded)

Footnotes:

[a] Costs and emission reduction are for 6 compressor seals (Model Plant B).

[b] Capital cost is based on 50 percent reciprocating and 50 percent centrifugal compressors:

1. 3 double distance pieces @ $2750 (Reference 1) = $8250
2. 3 distance pieces piping systems @ $1100 (Reference 1) = 3300
3. 3 centrifugal compressor seal vent piping systems @ $169 [BID cost of $154 from Table 8-1 plus 10 percent contingencies ($15)] = 507
4. Instrumentation system for purge gas supply (Reference 1) = 1960
5. 1 flare (Reference 1) = 7340
6. Piping to flare (Reference 1)* = 3700

Total = $25,057

*It is assumed that centrifugal compressors and reciprocating compressors are not used in the same plant. If the two types of compressors are mixed, two flare piping systems might be necessary. However, this case is considered unlikely because (1) a new plant would typically use all of one type of compressor, and (2) modified or reconstructed plants would be unlikely to have both types of compressors fall under NSPS requirements.

[c] 0.163 (capital recovery factor) x capital costs; see BID Table 8-5.

[d] 0.05 x capital cost.

[e] 0.04 x capital cost.

[f] No recovery credits are given for compressors because the cost analysis is based on the captured emissions being flared. Compressor seal vent emissions could be used for process heater fuel resulting in recovery of these emissions at their fuel value or recycled to a process line with a full product credit.

[g] Total annual cost (before credit) minus recovery credit.

[h] Based on uncontrolled VOC emission factor of 2.3 Mg/yr and 100 percent control efficiency for a closed vent and seal system. Compressor seal emission factor is from Reference 2.

[i] Obtained by dividing net annualized cost by total VOC emission reduction.

Table 4. ANNUALIZED CONTROL COSTS PER COMPONENT FOR OPEN-ENDED LINES[a] (June 1980 Dollars)

	CONTROL TECHNIQUE
	Caps
Installed Capital Cost[b]	61
Annualized Capital Control Equipment[c]	9.9
Annualized Operating Costs	
A. Maintenance[d]	3.0
B. Miscellaneous[e]	2.4
Total Annual Cost Before Credit	15.3
Recovery Credit[f]	28.1
Net Annualized Cost[g]	(12.8)
Total VOC Emission Reduction (Mg/yr)[h]	0.124
Cost Effectiveness ($/Mg VOC)[i]	(103)

[a] All costs and emission reduction estimates are for one piece of equipment in VOC service.

[b] See BID Table 8-1.

[c] 0.163 (capital recovery factor) x capital cost; see BID Table 8-5.

[d] 0.05 x capital cost.

[e] 0.04 x capital cost.

[f] Recovery credit based on uncontrolled VOC emission factor of 0.34. kg/day and total hydrocarbon emission factor of 0.53 kg/day, BID Table 3-1. Based on 100 percent control efficiency for caps and $192/Mg (recovered VOC value) and $61/Mg (recovered non-VOC hydrocarbon value) from BID Table 8-5.

[g] Total annual cost (before credit) minus recovery credit.

[h] Based on uncontrolled emission factor of 0.34 kg/day and 100 percent control efficiency for caps on open-ended lines.

[i] Obtained by dividing net annualized cost by total VOC emission reduction.

Table 5. ANNUALIZED CONTROL COSTS PER COMPONENT FOR SAMPLING CONNECTION SYSTEMS (June 1980 Dollars)[a]

	CONTROL TECHNIQUE
	Closed purge sampling system
Installed Capital Cost[b]	530
Annualized Capital Control Equipment[c]	86
Annualized Operating Costs	
A. Maintenance[d]	26
B. Miscellaneous[e]	21
Total Annual Cost Before Credit	133
Recovery Credit[f]	7
Net Annualized Cost[g]	126
Total VOC Emission Reduction (Mg/yr)[h]	0.018
Cost Effectiveness ($/Mg VOC)[i]	7,000

---

[a] All costs and emission reduction estimates are for one piece of equipment in VOC service.

[b] See BID Table 8-1.

[c] Capital recovery factor (10 years, 10 percent interest = 0.163) times capital cost.

[d] 0.05 x capital cost.

[e] 0.04 x capital cost.

[f] Recovery credit based on average of inlet gas sampling emission factor (VOC = 0.016 kg/day, THC = 0.32 kg/day) and product liquids emission factor (VOC 0.085 kg/day, THC = 0.095 kg/day) from BID Table 3-1 and recovered VOC value of $192/Mg and recovered non-VOC hydrocarbon (methane-ethane) value of $61/Mg from BID Table 8-5. Based on 100 percent control efficiency.

[g] Total annual cost (before credit) minus recovery credit.

[h] Based on average of gas and liquid sampling VOC emission factors in footnote f above.

[i] Obtained by dividing net annualized cost by total VOC emission reduction.

Table 6. ANNUALIZED CONTROL COSTS PER COMPONENT FOR VALVES[a]
(June 1980 Dollars)

	CONTROL TECHNIQUE	
	Quarterly Inspections	Monthly Inspections
Annualized Capital Initial Leak Repair[b]	0.84	0.84
Annualized Operating Costs		
Labor		
1. Monitoring[c]	2.4	7.1
2. Leak Repair[d]	3.8	3.9
3. Administrative and support[e]	2.5	4.4
Total Annual Cost Before Credit	9.5	16
Recovery Credit[f]	15	16
Net Annualized Cost[g]	(5.5)	0
Total VOC Emission Reduction (Mg/yr)[h]	0.051	0.055
Cost Effectiveness ($/Mg VOC)[i]	(110)	0
Incremental Cost Effectiveness ($/Mg VOC)[j]	(110)	1,400

[a] All costs and emission reduction estimates are for one piece of equipment in VOC service.

[b] Annualized initial leak repair costs are obtained by: number of leaks x repair time x labor rate x 1.4 (overhead) x 0.163. (Number of leaks based on 18 percent of valves leaking in initial survey.)
(0.18 x 1.13 hours x $18/hr x 1.4 x 0.163 = 0.84)

[c] Monitoring labor costs for valves based on the following: number of valves screened (number of valves x fractioned screened) x monitoring time (hours) x labor rate.
Quarterly: 3.94 x 2/60 x $18 = 2.4
Monthly: 11.79 x 2/60 x $18 = 7.1

[d] Leak repair costs are based on the following: fraction of sources maintained x repair time (hours) x labor rate =
Quarterly: 0.185 x 1.13 x $18 = 3.8
Monthly: 0.191 x 1.13 x $18 = 3.9

[e] 0.40 x (monitoring cost + leak repair cost).

[f] Recovery credit based on uncontrolled VOC emission factor of 0.18 kg/day and total hydrocarbon emission factor of 0.48 kg/day (BID Table 7-1), and a recovered VOC value of $192/Mg and recovered non-VOC hydrocarbon (methane-ethane) value of $61/Mg from BID Table 8-5. Based on 77 percent control efficiency for quarterly inspections and 84 percent control efficiency for monthly inspections (BID Table 7-1).

[g] Total annual cost (before credit) minus recovery credit.

[h] Based on uncontrolled VOC emission factor and control efficiencies presented in footnote f.

[i] Net annual cost divided by total VOC emission reduction.

[j] See Table 2, footnote n.

Table 7. ANNUALIZED CONTROL COSTS PER COMPONENT FOR PUMPS[a]
(June 1980 Dollars)

	CONTROL TECHNIQUE			
	Quarterly Inspections	Monthly Inspections	Dual Mechanical Seal System with Barrier Fluid System and Degassing Vents New	Dual Mechanical Seal System with Barrier Fluid System and Degassing Vents Retrofit
Installed Capital Cost				
A. Seal	0	0	1250[b]	1590[b]
B. Barrier Fluid System and Degassing Vents	0	0	5850[b]	5850[b]
Annualized Capital Cost				
A. Control Equipment[c]				
1. Dual Mechanical Seal				
o Seal	0	0	560[d]	720[e]
o Installation	0	0	49[f]	56[g]
2. Barrier Fluid System and Degassing Vents	0	0	950[h]	950[h]
3. Replacement Seal	55[i]	57[i]	0	0
B. Initial Leak Repair	22[j]	22[j]	0	0
C. Initial Seal Replacement	7.50[k]	7.50[k]	0	0
Annualized Operating Costs				
A. Maintenance[l]	0	0	355	372
B. Miscellaneous[m]	0	0	294	298
C. Labor				
1. Monitoring[n]	20	44	0	0
2. Leak Repair[n]	110	120	0	0
3. Administratove and Support[o]	52	66	0	0
Total Annual Cost Before Credit	270	320	2200	2400
Recovery Credit[p]	53	59	91	91
Net Annualized Cost [q]	217	261	2109	2309
Total VOC Emission[r] Reduction (Mg/yr)	0.26	0.29	0.44	0.44
Cost Effectiveness ($/Mg VOC)[s]	830	900	4800	5200
Incremental Cost Effectiveness ($/Mg VOC)[t]	830	1500	12,000	14,000

Table 7. ANNUALIZED CONTROL COSTS PER COMPONENT FOR PUMPS[a] (June 1980 Dollars) (Concluded)

Footnotes:

[a] All costs and emission reduction estimates are for one piece of equipment in VOC service.

[b] See BID Table 8-1.

[c] Cost of monitoring instrument is not included in the analysis.

[d] For new installation, annualized cost of dual seal = $1,250 (dual seal cost) x 0.58 (capital recovery factor for 2-year life) less single seal credit ($278 x 0.58).

[e] For retrofit installation, annualized cost of dual seal is same as new installation, except no single seal credit is given.

[f] Sixteen hours of installation at $18/hr, annualized over 10 years (0.163 x $288).

[g] Nineteen hours of installation at $18/hr, annualized over 10 years (0.163 x $342).

[h] 0.163 x capital cost.

[i] Replacement seal cost is 1/2 the cost of a new seal (old seal has salvage value). Cost corrected to June 1980 dollars ($140/seal) is based on Reference 3. Multiply replacement cost per seal by number of leaks per year. For quarterly and monthly inspections, number of leaks per pump equals 0.39 and 0.41, respectively (number of pumps x "fraction of sources operated on" from BID Table E-1).

[j] Annualized initial leak repair costs from BID Tables 8-5 and 8-6. Based on 33 percent of pump seals leaking in initial survey.

[k] Initial seal replacement cost = percent of pumps initially leaking x replacement seal cost x capital recovery factor (0.33 x $140 x 0.163 = $7.50).

[l] 0.05 x capital cost.

[m] 0.04 x capital cost.

[n] Monitoring labor and leak repair costs for pumps are based on BID Table 8-3 plus weekly visual inspection cost (based on 0.5 minutes/source, 52 times/yr, $18/hr) or $7.80 per source.

[o] 0.40 x (monitoring cost + leak repair cost).

[p] Recovery credit based on uncontrolled VOC emission factor of 1.2 kg/day and uncontrolled total hydrocarbon emission factor of 1.5 kg/day. Recovered VOC value of $192/Mg and recovered non-VOC (methane-ethane) value of $61/Mg are from Table 8-5. Based on 58 percent control efficiency for quarterly inspections, 65 percent control efficiency for monthly inspections, and 100 percent control efficiency for dual seal systems (from BID Table 7-1).

[q] Total annual cost (before credit) minus recovery credit.

[r] Based on uncontrolled VOC emission factors and control efficiencies in footnote p.

[s] Net annualized cost divided by total VOC emission reduction.

[t] See Table 2, footnote n.

REFERENCES

1. Memorandum from K.C. Hustvedt to J.F. Durham, EPA:OAQPS. Revised Cost Analysis for Reciprocating Compressor Seal Vent Controls. February 23, 1983 (Docket No. A-80-20-B (VOC) II-B-37).

2. Memorandum from K.C. Hustvedt to J.F. Durham, EPA:OAQPS. Revised Gas Plant Compressor Seal Emission Factor. February 10, 1983 (Docket No. II-B-35).

3. Fugitive Emission Sources of Organic Compounds - Additional Information on Emissions, Emission Reductions, and Costs. U.S. EPA, OAQPS, EPA-450/3-82-010, April 1982, p. 5-19 (Docket No. II-A-25).

APPENDIX I

REVISED PUMP SEAL LEAK DETECTION AND REPAIR EMISSION REDUCTION

Attached as Appendix I is a memorandum dated December 7, 1983 that describes the calculation of pump seal control emission reduction. Due to an error made the inputs to the Leak Detection and Repair (LDAR) model during the development of the BID, the values used throughout the BID chapters and previous appendices are incorrect. The memorandum attached documents the correct emission reduction values for natural gas plant pump seals, as well as the correct pump seal control cost effectiveness values for leak detection and repair programs.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

DEC 7 1983

MEMORANDUM

SUBJECT: Gas Plants Pump Seals Emission Reduction

FROM: K. C. Hustvedt KCH
Petroleum Section/CPB

TO: James F. Durham, Chief
Petroleum Section/CPB

While I was preparing for our November 29, 1983, meeting with OMB on the NSPS and CTG for VOC equipment leaks from gas plants, I recalculated the cost effectiveness of leak detection and repair programs (LDRP) for pump seals. In checking my results against the numbers developed for the CTG and NSPS, I found that my new calculations estimated a much higher emission reduction for all monitoring intervals. I discovered that in our computer runs for gas plants we had used 87 percent emission reduction for repair of leaking pump seals (F2 equals 0.13 in the leak detection and repair (LDAR) model)[1], while in the AID[2] we had used an F2 value of 0.028 (97.2 percent emission reduction). As discussed in the AID, it is likely that repair (replacement) of a leaking pump seal will result in essentially 100 percent emission reduction or an F2 of 0.00, so that the AID value is a low estimate of the emission reduction from repair. Because we feel the LDAR inputs developed in the AID are appropriate for all of our VOC equipment leak projects, I have recalculated the pump impacts using 0.028 for F2.

Attached are the LDAR model inputs and outputs for monthly, quarterly, semiannual and annual LDRP. I have summarized the results of these runs, including the incremental impacts between alternative LDRP, in Table 1. The costs and emission reductions shown in Table 1 are based on 100 pump seals to minimize effects of rounding on the calculated results. To correct these numbers to model plant numbers, the costs or emission reductions should be multiplied times the number of pump seals in the model plant divided by 100. Since there are 6 pumps in model plant B, this means you would multiply these numbers times 0.06 to get model plant B impacts. The cost effectiveness numbers are independent of number of pumps so they are already correct for all the model plants.

REFERENCES

1. T. W. Rhoads, PES, Inc. to Docket A-80-20-B. "Evaluation of the Effects of Leak Detection and Repair on Fugitive Emissions Using the LDAR Model," November 1, 1982, Docket Reference Number II-B-18.

2. Fugitive Emission Sources of Organic Compounds--Additional Information on Emissions, Emission Reductions, and Costs, EPA-450/3-82-010, April 1982.

Attachments

cc: Dianne Byrne, EPA/SDB
Fred Dimmick, EPA/SDB
Tom Norwood, PES
Tom Rhoads, PES
Docket A-80-20-B

Table 1. LDAR ANALYSIS FOR NATURAL GAS PLANT PUMPS - CTG & NSPS[a]

Case	Monitoring Interval (Months)	Emission Reduction (Percent)	Emission Reduction (Mg/yr)	Change E.R. (Mg/yr)	Net Cost ($/yr)	Cost Change ($/yr)	Cost Effectiveness ($/Mg)	Incremental C/E ($/Mg)	Notes[b]
M	1	87.2	38.2		23,200		610		
				4.0		3,200		800	M to Q
Q	3	78.0	34.2		20,000		587		
				5.8		700		121	Q to SA
SA	6	65.0	28.4		19,300		680		
				10.2		300		29	SA to A
A	12	41.6	18.2		19,000		1,040		
				16.0		1,000		62	Q to A

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[a] Based on 100 pump seals.
[b] Increments between the two monitoring intervals shown.

```
                         INPUT   DATA

                                  PLANT NATUGAS CTG&NSPS
                              (FOR LIGLT LIQUID PUMPS )


FOR EXAMINING EMISSION REDUCTIONS DUE TO LDAR:     (MONTHLY)
_____________________________________________

     MONITORING INTERVAL (MONTHS)                                    1
     TURNAROUND FREQUENCY (MONTHS)                                  24
     EMISSION FACTOR (KG/HR/SOURCE)                               0.05
     LEAK OCCURRENCE RATE (% PER PERIOD)                           3.4
     INITIAL % LEAKING                                            33.0
     EMISSIONS REDUCTION FOR UNSUCCESSFUL REPAIR (%)               0.0
     EMISSIONS REDUCTION FOR SUCCESSFUL REPAIR (%)                97.2
     EARLY LEAK RECURRENCE (% OF REPAIRS)                          0.0
     UNSUCCESSFUL REPAIR RATE (%)                                  0.0
     UNSUCCESSFUL REPAIR RATE (%) AT TURNAROUND                    0.0

FOR EXAMINING THE COSTS OF LDAR:
________________________________

     TOTAL NUMBER OF SOURCES                                       100
     MONITORING TIME PER SOURCE INSPECTION (MINUTES)              10.0
     VISUAL MONITORING TIME PER SOURCE (MINUTES)                  0.50
     NUMBER OF VISUAL INSPECTIONS PER YEAR                          52
     REPAIR TIME PER SOURCE (MINUTES)                              960
     LABOR RATE ($/HOUR)                                            18
     PARTS COST PER SOURCE ($)                                     140
     ADMINISTRATIVE & SUPPORT OVERHEAD COST FACTOR (%)            40.0
     CAPITAL RECOVERY FACTOR (%)                                  16.3
     RECOVERY CREDIT FOR EMISSIONS REDUCTION ($/MG)                207


FOR EXAMINING EMISSION REDUCTIONS DUE TO LDAR:     (QUARTERLY)
_____________________________________________

     MONITORING INTERVAL (MONTHS)                                    3
     TURNAROUND FREQUENCY (MONTHS)                                  24
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                              I N P U T   D A T A

                                           PLANT NATUGAS CTG&NSPS
                                      (FOR LIGLT LIQUID PUMPS)
     EMISSION FACTOR (KG/HR/SOURCE)                              0.05
     LEAK OCCURRENCE RATE (% PER PERIOD)                          10.2
     INITIAL % LEAKING                                            33.0
     EMISSIONS REDUCTION FOR UNSUCCESSFUL REPAIR (%)               0.0
     EMISSIONS REDUCTION FOR SUCCESSFUL REPAIR (%)                97.2
     EARLY LEAK RECURRENCE (% OF REPAIRS)                          0.0
     UNSUCCESSFUL REPAIR RATE (%)                                  0.0
     UNSUCCESSFUL REPAIR RATE (%) AT TURNAROUND                    0.0

FOR EXAMINING THE COSTS OF LDAR:
________________________________

     TOTAL NUMBER OF SOURCES                                       100
     MONITORING TIME PER SOURCE INSPECTION (MINUTES)              10.0
     VISUAL MONITORING TIME PER SOURCE (MINUTES)                  0.50
     NUMBER OF VISUAL INSPECTIONS PER YEAR                          52
     REPAIR TIME PER SOURCE (MINUTES)                              960
     LABOR RATE ($/HOUR)                                            18
     PARTS COST PER SOURCE ($)                                     140
     ADMINISTRATIVE & SUPPORT OVERHEAD COST FACTOR (%)            40.0
     CAPITAL RECOVERY FACTOR (%)                                  16.3
     RECOVERY CREDIT FOR EMISSIONS REDUCTION ($/MG)                207


FOR EXAMINING EMISSION REDUCTIONS DUE TO LDAR:   (SEMI-ANNUAL)
______________________________________________

     MONITORING INTERVAL (MONTHS)                                    6
     TURNAROUND FREQUENCY (MONTHS)                                  24
     EMISSION FACTOR (KG/HR/SOURCE)                              0.05
     LEAK OCCURRENCE RATE (% PER PERIOD)                          20.4
     INITIAL % LEAKING                                            33.0
     EMISSIONS REDUCTION FOR UNSUCCESSFUL REPAIR (%)               0.0
     EMISSIONS REDUCTION FOR SUCCESSFUL REPAIR (%)                97.2
     EARLY LEAK RECURRENCE (% OF REPAIRS)                          0.0
     UNSUCCESSFUL REPAIR RATE (%)                                  0.0
     UNSUCCESSFUL REPAIR RATE (%) AT TURNAROUND                    0.0
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                         I N P U T   D A T A

                                   PLANT NATUGAS CTG&NSPS
                             (FOR LIGLT LIQUID PUMPS)

FOR EXAMINING THE COSTS OF LDAR:
______________________________

     TOTAL NUMBER OF SOURCES                                           100
     MONITORING TIME PER SOURCE INSPECTION (MINUTES)                  10.0
     VISUAL MONITORING TIME PER SOURCE (MINUTES)                      0.50
     NUMBER OF VISUAL INSPECTIONS PER YEAR                              52
     REPAIR TIME PER SOURCE (MINUTES)                                  960
     LABOR RATE ($/HOUR)                                                18
     PARTS COST PER SOURCE ($)                                         140
     ADMINISTRATIVE & SUPPORT OVERHEAD COST FACTOR (%)                40.0
     CAPITAL RECOVERY FACTOR (%)                                      16.3
     RECOVERY CREDIT FOR EMISSIONS REDUCTION ($/MG)                    207


FOR EXAMINING EMISSION REDUCTIONS DUE TO LDAR:      (ANNUAL)
______________________________________________

     MONITORING INTERVAL (MONTHS)                                       12
     TURNAROUND FREQUENCY (MONTHS)                                      24
     EMISSION FACTOR (KG/HR/SOURCE)                                   0.05
     LEAK OCCURRENCE RATE (% PER PERIOD)                              40.5
     INITIAL % LEAKING                                                33.0
     EMISSIONS REDUCTION FOR UNSUCCESSFUL REPAIR (%)                   0.0
     EMISSIONS REDUCTION FOR SUCCESSFUL REPAIR (%)                    97.2
     EARLY LEAK RECURRENCE (% OF REPAIRS)                              0.0
     UNSUCCESSFUL REPAIR RATE (%)                                      0.0
     UNSUCCESSFUL REPAIR RATE (%) AT TURNAROUND                        0.0

FOR EXAMINING THE COSTS OF LDAR:
______________________________

     TOTAL NUMBER OF SOURCES                                           100
     MONITORING TIME PER SOURCE INSPECTION (MINUTES)                  10.0
     VISUAL MONITORING TIME PER SOURCE (MINUTES)                      0.50
     NUMBER OF VISUAL INSPECTIONS PER YEAR                              52
     REPAIR TIME PER SOURCE (MINUTES)                                  960
```

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                              I N P U T   D A T A

                                        PLANT NATUGAS CTG&NSPS
                                 (FOR LIGLT LIQUID PUMPS)
LADOR RATE ($/HOUR)
PARTS COST PER SOURCE ($)                                  18
ADMINISTRATIVE & SUPPORT OVERHEAD COST FACTOR (%)         140
CAPITAL RECOVERY FACTOR (%)                               40.0
RECOVERY CREDIT FOR EMISSIONS REDUCTION ($/MG)            16.3
                                                           207
```

SUMMARY OF ESTIMATED EMISSION FACTORS (KG/HR) AND PERCENT REDUCTION IN MASS EMISSIONS FOR PUMPS/LIGLT LIQUID SERVICE BY TURNAROUND - PLANT NATUGAS CTG&NSPS

TURNAROUND PERIOD	MEAN EMISSION-KG/HR		PERCENT REDUCTION	
			COMPARED TO INITIAL EMISSION	COMPARED TO EMISSION FOR WHICH NO MAINTENANCE WAS DONE DURING PERIOD
1	0.0064	MONTHLY	87.2	92.2
2	0.0064		87.2	81.3
3	0.0064		87.2	81.3
1	0.0110	QUARTERLY	78.0	86.7
2	0.0110		78.0	69.8
3	0.0110		78.0	69.8
1	0.0175	SEMI-ANNUAL	65.0	78.8
2	0.0175		65.0	56.5
3	0.0175		65.0	56.5
1	0.0292	ANNUAL	41.6	65.1
2	0.0292		41.6	38.3
3	0.0292		41.6	38.3

PLANT NATUGAS CTG&NSPS SUMMARY:

AVERAGE ANNUAL COST EFFECTIVENESS
(MONTHLY LDAR)

SOURCE TYPE	EMISSION REDUCTION (MG/YR)	RECOVERY CREDIT	NET COSTS	GROSS COST EFFECTIVENESS (PER MG)	NET COST EFFECTIVENESS (PER MG)	
PUMPS						
LIGLT LIQUID	38.2	$ 7,910	$ 23,300	$ 817	$ 610	MONTHLY
LIGLT LIQUID	34.2	7,070	20,000	794	587	QUARTERLY
LIGLT LIQUID	28.4	5,890	19,300	887	680	SEMI ANNUAL
LIGLT LIQUID	18.2	3,770	19,000	1,250	1,040	ANNUAL
	-------	----------	----------	-------	-------	
PLANT TOTAL	119	$ 24,600	$ 81,700	$ 893	$ 686	